การศึกษาความเป็นไปได้ในการใช้ประโยชน์จากก๊าซธรรมชาติที่ถูกเผาทิ้งสำหรับ แหล่งน้ำมันนอกรูปแบบในประเทศไทย

นายพงศธร ห.เพียรเจริญ

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
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FEASIBILITY STUDY OF FLARED GAS UTILIZATION FOR UNCONVENTIONAL OILFIELD IN THAILAND

Mr. Pongsathorn Horpiencharoen

A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
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Field of Study	Petroleum Engineering
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Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

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พงศธร ห.เพียรเจริญ : การศึกษาความเป็นไปได้ในการใช้ประโยชน์จากก๊าซธรรมชาติที่ถูกเผาทิ้งสำหรับแหล่งน้ำามันนอกรูปแบบในประเทศไทย (FEASIBILITY STUDY OF FLARED GAS UTILIZATON FOR UNCONVENTIONAL OILFIELD IN THAILAND) อ. ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. จิรวัฒน์ ชีวรุ่งโรจน์, อ. ที่ปรึกษาวิทยานิพนธ์ร่วม: ดร. วิศรุต ตั้งสุนทรขัณฑ์, 103 หน้า.

แหล่งผลิตน้ำมันดิบที่ทำการศึกษาเป็นแหล่งน้ำมันดิบขนาดเล็กแห่งหนึ่งในประเทศไทย ซึ่งผลิตน้ำมันดิบประมาณ 8,500 บาเรลต่อวันและก๊าซธรรมชาติซึ่งเป็นผลพลอยได้จากน้ำมันอีก 1,300,000 ลูกบาศก์ฟุตต่อวัน ซึ่งก๊าซถูกกำจัดโดยการเผาทิ้ง ความท้าทายของแหล่งน้ำมันดิบแห่งนี้คือการที่มีหลุมผลิตทั้งหมด 29 หลุมผลิตจาก 21 ตำแหน่ง ขณะที่แต่ละหลุมมีชุดอุปกรณ์การผลิตน้ำมันแยกเป็นของตัวเองโดยไม่มีการเชื่อมต่อกัน นอกจากนี้แหล่งผลิตน้ำมันแห่งนี้ยังเป็นแหล่งผลิตนอกรูปแบบซึ่งผลิตน้ำมันจากแหล่งกักเก็บหินภูเขาไฟ อายุการผลิตของแต่ละหลุมนั้นสั้นกว่าการผลิตของแหล่งน้ำมันแบบดั้งเดิมซึ่งปรกติจะผลิตน้ำมันจากแหล่งกักเก็บหินทราย

การศึกษานี้ใช้วิธี Decline Curve Analysis (DCA) ในการคาดการณ์ปริมาณก๊าซธรรมชาติและอายุของหลุมผลิตแต่ละหลุม ผลการศึกษาแสดงให้เห็นว่าก๊าซซึ่งเป็นผลพลอยได้จากน้ำมันดิบมีปริมาณน้อยและอายุของหลุมผลิตค่อนข้างสั้นเพียง 1-2 ปีโดยเฉลี่ย ซึ่งข้อมูลนี้ได้นำมาใช้ในการศึกษาความเป็นไปได้ของการนำก๊าซมาใช้ประโยชน์ 4 ทางเลือก คือ การใช้ก๊าซผลิตไฟฟ้า, โรงงานก๊าซธรรมชาติอัด (CNG), โรงงานก๊าซธรรมชาติเหลว (LNG), และการใช้ก๊าซผลิตไฟฟ้าภายในแหล่งผลิต ทางเลือกดังกล่าวนี้ได้ถูกศึกษาในเชิงเทคนิคและเชิงเศรษฐกิจซึ่งผลของการศึกษาพบว่ามีเพียงการใช้ก๊าซผลิตไฟฟ้าภายในแหล่งผลิตเท่านั้นที่มีความเป็นไปได้ในการดำเนินโครงการ เนื่องจากทางเลือกอื่นๆมีข้อจำกัดในเชิงเศรษฐกิจและอายุของหลุมผลิตที่สั้นเพียง 1-2 ปี

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต
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In this thesis, an onshore marginal oilfield is studied. The field currently produces oil approximately 8,500 barrels per day as well as natural gas around 1,300,000 scfd (standard cubic feet per day) which is disposed by flaring. The challenging of this field is that there are twenty nine oil wells producing oil from twenty one well site locations while each well has its own processing equipment's and does not connect to each other. Furthermore, this field is an unconventional oilfield which produced from volcanic rock reservoir. The production life of each well is shorter than conventional oilfield production that normally produced from sandstone reservoir. These reasons are taken into account for considering gas utilization options.

The production forecast in this thesis has been performed by Decline Curve Analysis (DCA) method the result showed small gas production forecast and very short production life, which is only 1-2 years in average. These data has been used for feasibility study for gas utilization in 4 possible well known options namely power generation, Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG), and on-site gas utilization. These options are studied in detail on technical and economic feasibility study. According to the studied result, only on-site gas utilization is technical and economic feasible. The rest options are infeasible because the limitation of economic reason and short production life.

Department: Mining and Petroleum Engineering	Student's Signature
Field of Study: Petroleum Engineering	Advisor's Signature
Academic Year: 2011	Co-advisor's Signature

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List of Abbreviations

API	American petroleum institute
bbl	barrel (bbl/d : barrel per day)
bopd	barrel of oil per day
CDM	clean development mechanism
CERs	certified emission reduction
CNG	Compressed Natural Gas
DCA	decline curve analysis
ESP	electric submersible pump
GHG	greenhouse gas
IRR	internal rate of return
km	Kilometers
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MW	megawatt
mscfd	thousand standard cubic feet per day
mmscfd	Million standard cubic feet per day
NPV	net present value
O&M	Operating and Maintenance
PE	Polyethelyne
scfd	standard cubic foot
stb	stocktank barrel

CHAPTER I
INTRODUCTION

Nowadays, global warming is one of the most severe problems which impact the world by climate change. The main cause of global warming is greenhouse gas (GHG) emission which prevents heat ray from reflecting back to space. This leads to greenhouse effect which makes world‘s average temperature higher.

The highest amount of greenhouse gas in the earth‘s atmosphere is Carbon dioxide which occurs from fossil fuel combustion. Therefore, one method that can relieve global warming is to reduce CO_2 emission and initiate more energy utilization projects.

In petroleum industry, associated gas has to be flared because of safety purpose. However, gas flaring constitutes a waste of economically valuable resources and contributes significantly to global warming. According to current severe global warming problem, the conventional associated gas flaring process supposes to be developed in order to reduce CO_2 emission and decrease wasting energy. Therefore, the main objective of this thesis is to propose the technically and economically feasible options of flared gas utilization project.

This thesis will study feasibility of flared gas utilization for unconventional oilfield. ―Unconventional" term in this study relates to reservoir and oilfield characteristics. The reservoir is volcanic reservoir which causes some behaviors that different from those conventional sandstone reservoirs. Besides, the well sites in this oilfield are scattered located. The distance between each well is around 1-2 kilometers.

The field currently produces oil approximately 8,500 barrels per day as well as natural gas around 1,300,000 scfd (standard cubic feet per day) which is disposed by flaring. The challenging of this field is that there are twenty nine oil wells producing oil from twenty one well site locations while each well has its own processing equipment‘s and does not connect to each other. Furthermore, this field is an unconventional oilfield which produced from volcanic rock reservoir. The production life of each well is shorter than conventional oilfield production that normally produced from sandstone reservoir. This reason is taken into account for considering gas utilization options. The gas utilization projects are proposed based on technical and economic feasibility study result, which especially considered for this unique unconventional oilfield.

According to current technology, there are several options that might be considered in this feasibility study such as Liquefied Natural Gas (LNG), Compressed Natural Gas (CNG), 1 MW gas power plant, on-site gas engine, and on-site gas generator. These options have been reviewed and proposed the most feasible option for this oilfield.

This feasibility study will consider the important factors as follows:

1. Economically feasible
2. Technically feasible
3. Reservoir limitation and characteristics

The option that passes all of these criteria is highly recommend for implementation. However, when the new technology presented, some options might have significantly lower cost. It could potentially make those options more economically feasible.

1.1 Objectives

1. To estimate gas reserve for evaluating the potential of flared gas utilization of an unconventional oilfield in Thailand.
2. To perform feasibility study of flared gas utilization for an unconventional oilfield in Thailand.
3. To propose the favorable and environment friendly flared gas utilization option for an unconventional oilfield in Thailand.

1.2 Methodology

1. Study in detail about this unconventional oilfield characteristic, production behavior, production history and field development history.
2. Review previous literature about gas utilization technology for small-scale development, volcanic reservoir, and gas utilization project management.

3. Determine future production life and future production rate by using decline curve analysis.
4. Study technical and economic of each available gas utilization options based on technical and economic aspects.
5. Propose feasible flared gas utilization option and conclude amount of utilized associated gas, operation cost saving, and GHG emission reduction.

1.3 Scope of work

This thesis scope is to study each possible small-scale flared gas utilization options which consider two main aspects consist of flared gas utilization technology (technical feasibility), and economic analysis (economic feasibility) based on unconventional oilfield conditions.

The main objective of this thesis is to propose feasible gas utilization option. Therefore, the study will emphasize on project planning that is expected to be applied in real practice for providing better option for natural gas management as soon as possible.

This oilfield is studied on production behavior as input to determine a guideline for gas utilization options. Moreover, production life and future oil and gas production rate will be evaluated based on field data and production history by using decline curve analysis (DCA).

Since, this oilfield has been operated for more than 10 years, there are a lot of abandon wells data which can be used as additional data for minimum-maximum production life reference. For economic analysis, if the gas utilization project could reach payback period within reference average production life, the gas utilization project would be worth for an investment.

For technical aspect, there are three main problems which needed to be considered. Firstly, the scattering oil well location problem, since there are twenty nine oil wells scatter in twenty one separate locations. The distance between each well is the major concern of pipeline construction cost. Moreover, gas compressor has to be installed because of pressure drop in long distance gas transmission. This will add more cost to off-site gas utilization project. Secondly, the fast production decline rate problem due to the volcanic reservoir characteristics, which results in short production life. Thirdly, highly variable flow rate problem which could make the gas electricity generating system become unreliable. Also the well could be temporally shut in because of low oil flow rate or excess water production. These three factors mainly affect the study in both technical and economic aspect.

After determining production life and future production rate, the flaring reduction technology will be considered base on amount of estimated flared gas and appropriate investment. Then, each option will be performed technical and economic feasibility study. The feasible option will be proposed with amount of reduced GHG emission reduction.

CHAPTER II

LITERATURE REVIEW

Various types of gas utilization projects have been studied throughout the world. Even there is still no report about gas utilization of marginal oilfield which focuses on producing oil from volcanic reservoir, but the concepts of flared gas management from previous studies are useful information for this thesis.

2.1 Associated Gas Utilization and Clean Development Mechanism

These literatures have been reviewed for studying the concept of gas utilization and flared gas management from the successful projects.

Kia and Sikchi proposed the associated gas utilization project in Sabah, Malaysia. 1 billion US Dollars was invested by a government in a gas utilization project in order to stop the associated gas venting from offshore production platforms.

The new platform facilities was built close to existing oil production platforms for transmission of 90 mmscfd of gas to Labuan island. These amount of gas would be utilized by 47 MW power plant, an iron plant and a methanol plant.

Global Gas Flaring Reduction, a Public-Private Partnership, The World Bank Group (WBG) studied the associated gas utilization opportunities for small-scale uses from rural electrification to commercial and industrial usage. The feasibility of using flared gas in various applications was studied. Moreover, several case studies from Ecuador, Chad, and Mozambique, have been reported with projects detail, lesson learn, and guideline which could lead to a detailed feasibility study.

Indonesia Associated Gas Survey – Screening & Economic Analysis Report, The World Bank Group (WBG) reported the challenges for establishing flaring reduction project in Indonesia. They evaluated the technical, economic, and financial viability of the project, and provided recommendations for implementing these projects in the near future. The scattered and remote locations of associated gas fields in Indonesia presented a unique challenge for flare gas utilization. The report is concluded that on-site power generation is a favorable option when gas valuation is low and CNG or off-site power generation is recommended when gas valuation is high.

Annual Report 2008, Department of Mineral Fuels (DMF), The article named “Utilization of associated gas form oil production” was launched by the DMF to report the flaring reduction and utilization projects of S1 and nearby oilfields. There were three efficient projects reported about their performance and method of associated gas utilization. The projects are namely as application in small power generators (Pratu Tao field), gas for community agriculture and environmental project (Nong Tum Field), and Trial LNG production project.

Noppanan Nopsiri, proposed his thesis “Utilization of associated gas from onshore oil field production of Thailand”. He studied and listed gas utilization options and constraints. The onshore oil fields in Thailand are preliminary previewed and, then Thailand onshore oil field case was selected and studied in details. The possible options for small scale gas utilization are considered for the next step of study. The field criteria to considerations are studied which the associated gas reserve and future production are the important parameters for this study, and they depend on reserve and future production of crude oil. The determined associated gas reserve and production forecast was set to 3 different cases of outcome. The sub-fields in the case field are screened by the criteria to get the 2 sub-field candidates. The financial analysis comes into play to determine the feasible fields with the suitable option. The study concludes that the utilization of associated gas from onshore oil field production in Thailand is potent enough to implement.

Spiers et al. presented “West African Gas Pipeline as a Clean Development Mechanism Project under the Kyoto Protocol”. The West African Gas Pipeline (WAGP) is a proposed 500-mile (800-kilometer) pipeline being designed to transport Nigerian gas to Benin, Togo and Ghana. The pipeline would collect unused natural gas from Nigerian oilfields and transport it to neighboring countries where it would displace higher-carbon fuels in power plants. The benefits of the WAGP project noted in this study are based on a WAGP Development Plan that assumes a gradual increase in natural gas delivery from 100 MMscfd in 2003 to as high as 300 MMscfd in 2023. Actual project benefits would depend on the ultimate size of the project and on the actual amount of natural gas delivered. By comparing these two development scenarios, the WAGP project was evaluated for its potential to reduce GHG emissions growth; enhance capacity building and sustainable development in the host countries; and promote environmental benefits in the region.

Reductions in emissions caused by the reductions in flaring of the gas in Nigeria, and CDM credits resulting from such emissions reductions, could provide the necessary incentive to overcome the economic disadvantage of gas relative to lower quality and lower cost fuels. These mechanisms could provide the proper incentives to select higher quality natural gas.

Ozumba, Amam, and Pepple, presented paper named ―Clean Development Mechanism—The SPDC Afam Power Project”. The paper described Afam CDM, the most advanced in SPDC and one of the first in Nigeria was developed as a pilot ‗learning by doing‘ project to access the emerging carbon market. Afam CDM is built around the development of a power generation project involving the replacement of old inefficient generating plants with Combined Cycle Gas Turbines (CCGT). This would displace inefficient power sources and contribute to a reduction in emissions.

All of these previous studies on associated gas utilization and gas project management gave guidelines for studying these topics. Some papers have reported the successful of gas utilization or technical and economic viable projects that have been implemented in certain countries. The technologies and gas utilization ideas that could possibly be adjusted for using with the small-scale gas utilization in Thailand will be picked for reviewing as potential candidates.

Indonesia Associated Gas Survey – Screening & Economic Analysis Report by the World Bank Group (WBG), and Utilization of associated gas from onshore oil field productionof Thailand by Noppanan Nopsiri, have published study result that can be used as references. Their study objectives have been planned for later researcher to use their approach as a standard for considering small-scale gas utilization in a new field. Therefore, this thesis would partly refer to some of technologies, approaches, and opportunities for gas utilization from these previous studies.

For Carbon Emission Reduction, this thesis will refer to method from West African Gas Pipeline as a Clean Development Mechanism Project under the Kyoto

Protocol and Clean Development Mechanism—The SPDC Afam Power Project. These papers showed the standard method for calculating amount of emission reduction, which will be used as reference for this thesis when mentioning about emission reduction.

2.2 Volcanic Reservoir Characteristics

To understand the characteristic of volcanic reservoir, These literatures have been reviewed as follows:

Thomas Kalan, Sitorus, and Eman presented paper named ―Jatibarang Field, Geologic Study of Volcanic Reservoir for Horizontal Well Proposal". This paper gathered data from previous work of feasibility study on horizontal drilling to improve production from Jatibarang Volcanics. The feasibility concluded that drilling horizontal wells would increase recovery from volcanic reservoir. The geologic feasibility study was aimed at determining reservoir types in which horizontal drilling and production techniques would lead to improved drainage. The geologic work divided into two stages. The first stage is log correlations of the tertiary sedimentary sequence above the volcanics. The second stage was emphasized on isolating productive intervals of the volcanic reservoir and on log correlations of the productive zones.

GuoXin et al. presented a paper name ―Petrophysical Characterization of a Complex Volcanic Resevoir". The study proposed a methodology for characterizing a complex volcanic reservoir in China. Methodologies for determination of lithology, porosity, pore network geometry, permeability, and water saturation in these complex volcanic reservoirs have been described. Implementing these methodologies in a proposed workflow has enabled a
comprehensive evaluation of reservoir properties.

Zhao et al. presented a paper named ―Development and Field Application for Integrated Fracturing Technology of Volcanic Reservoir". The paper described volcanic reservoir behavior and necessity of using man-made fracture to enhance oil recovery the permeability.

Farooqui et al. issued an article named ―Evaluating Volcanic Reservoirs". This article describes the history of oil production from volcanic reservoir, the complexity of volcanic reservoirs, and presents technologies that have proved successful in characterizing them. The discussion begins with a review of igneous rock types and follows with an examination of the effects of igneous process on petroleum systems. Two field examples highlight formation evaluation in volcanic rocks. A case study from a gas-rich reservoir in China presents a technique that combines conventional logging measurements and image logs with neutron-capture spectroscopy and nuclear magnetic resonance. An example from India demonstrates the importance of incorporating borehole resistivity images in the evaluation of oil-bearing volcanic rock.

These papers been reviewed in order to know how to study volcanic reservoir. Most patterns and approaches for describing the reservoir in this thesis referred from these papers. The geologic part that describes volcanic reservoir in Chapter III was based on approach form ―Jatibarang Field, Geologic Study of Volcanic Reservoir for Horizontal Well Proposal". The Petrophysics and reservoir characterization were based on ―Petrophysical Characterization of a Complex Volcanic Resevoir" and the rest papers in this section

2.3 Associated gas utilization opportunities in Thailand

Utilization of associated gas from onshore oil field production of Thailand is the study conducted by Noppanan Nopsiri in 2007. He studied in detail about gas utilization opportunities and evaluated every oilfield in Thailand. Then, the most potential oilfield was selected for studying feasibility of gas utilization.

According to the study result, every onshore oilfield in Thailand has small associated gas production. The most potential field was selected for the study and 4 gas utilization options were reviewed. The options are as follows:

1. Power generator fueled by associated gas
2. LNG (Liquefied Natural Gas) production for transportation and NGV (Natural Gas Vehicle) car fuel
3. Associated natural gas for fuel and directly pipeline to the community
4. Utilization of LNG by-product

These options were already studied in detailed and selected according to the possibility and suitability for Thailand gas utilization. Thus, they will still be used in this thesis as potential options.

2.4 Liquefied Natural Gas (LNG)

According to Kumar, S., ―Gas production engineering", LNG process can be described as follows:

1. Gas treatment step

The gas from reservoir may also contain components such as nitrogen, carbon dioxide and sulfur compounds. The feed gas has to be treated for removal of impurities before it can be liquefied. Hence, gas treatment is required for the removal of impurities to meet the specifications.

The gas treatment typically comprises of:

- Gas reception facilities
- Acid gas removal and disposal section
- Gas dehydration
- Mercury removal
- Particle filtration

2. Liquefaction step

The liquefaction plant is the heart of the LNG value chain. LNG liquefaction plants are generally classified as baseload or peak shaving, depending on their purpose and size. The discussion here is directed towards baseload LNG plants. The liquefaction process entails cooling the clean feed gas to -161ºC using mechanical refrigeration. A refrigerant gas is compressed, cooled, condensed and let down in pressure through a valve that reduces its temperature by the Joule-Thomson effect. The refrigerant gas is then used to cool the feed gas. The temperature of the feed gas is eventually reduced to -161ºC at which temperature methane, the main constituent of natural gas, liquefies. At this temperature all the other hydrocarbons in the natural gas will also be in liquid form. In the liquefaction process, constituents of the natural gas (propane, ethane and methane) are typically used as component
recovery is normally included in the LNG liquefaction facility. LPG and condensate may also be recovered as by-products.

There are three main types of liquefaction cycles namely cascade, mixed refrigerant, and expansion cycle. Most commercially available liquefaction processes are based on these cycles or a combination of these cycles. These processes include the Pure Component Cascade Cycle, Propane Pre-cooled Mixed Refrigerant Cycle, Dual Mixed Refrigerant Cycle, Single Mixed Refrigerant Cycle, Mixed Fluid Cascade Process and others.

The liquefaction plant typically involves the main following steps:

- Initial cooling feed gas to remove heavier hydrocarbons
- Liquid removal
- Total liquefaction of natural gas
- The end flash or nitrogen rejection section to reduce pressure to near atmospheric pressure
- LNG send out and storage

2.5 Compressed Natural Gas (CNG)

Compressed Natural Gas (CNG) is a substitute for gasoline (petrol), diesel, or propane fuel. It is considered to be an environmentally "clean" alternative to those fuels and it is much safer than other motor fuels in the event of a fuel spill: natural gas is lighter than air, so it disperses quickly when leaked or spilled. It is made by compressing natural gas (which is mainly composed of methane (CH_4)),to less than 1% of its volume at standard atmospheric pressure. It is stored and distributed in hard containers, at a normal pressure of 200–220 bar (20–22 MPa), usually in cylindrical or spherical shapes to maintain equal pressure on the walls of the containers. In response to high fuel prices and environmental concerns, compressed natural gas is starting to be used in light-duty passenger vehicles and pickup trucks, medium-duty delivery trucks, and in transit and buses.

CHAPTER III

UNCONVENTIONAL OILFIELD DESCRIPTION

One of the important terms in this thesis topic is ―unconventional oilfield” which relates to the uniqueness of this oilfield. There are several reasons that the term ―unconventional oilfield” should be used as follows:

1. Reservoir Characteristic

This oilfield has been developed by focusing on production from volcanic layers which there are not so many oilfields in the world that produce from this kind of reservoir.

2. Scattered surface facilities

The field production facilities are wellsite based, sized to individual well production rates. Presently, there are twenty nine oil wells producing at twenty one separate locations. The operation does not have a centralized processing facilities or a network of intra-site flowlines.

The objective of this chapter is to present the characteristic of this unconventional reservoir by all sorts of both surface and subsurface data. Therefore, the chapter will be divided into 2 parts which are surface production facilities part and reservoir characteristic part.

3.1 Surface Production Facilities

According to the scattered well site which mostly located around 1 km between each well, the field production facilities are well site based, sized to individual well production rates. Presently, there are twenty nine oil wells producing at twenty one separate locations. The operation does not have a centralized processing facilities or a network of intra-site flowlines. Field schematic is illustrated in Figure 3.1.

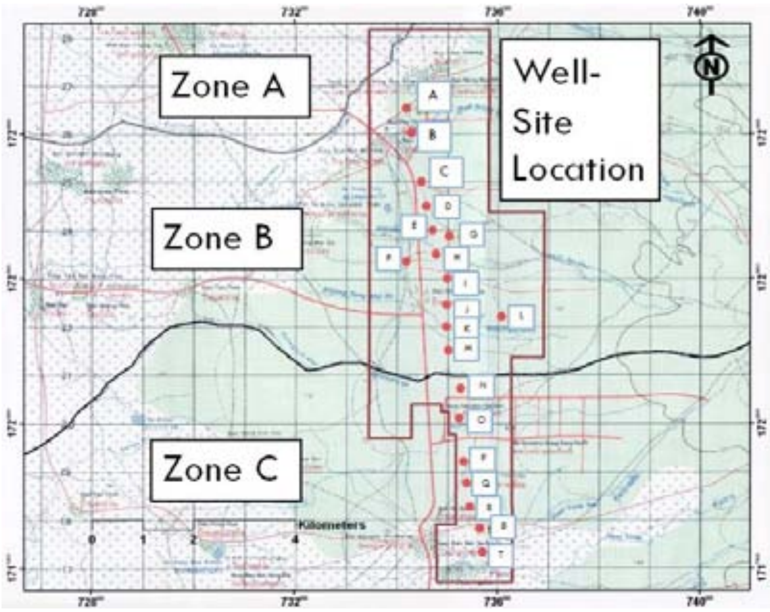

Figure 3.1 Scatter Wellsite along north-south direction

There is a variation in term of equipment sizes and number of tanks to accommodate the varying, and sometimes rapid, decline of production from individual wells. Artificial lift is required on most wells early in their production life to compensate for declining reservoir pressure. Due to the uncertainties and unpredictability in productivity and decline rates, the facilities are installed in a manner that allows the majority of the equipment to be reutilized on other wells after well abandonment.

3.1.1 Wellsite layout

The stand-alone production facility for each wellsite is illustrated in Figure 3.2. This type of installation is anticipated for all other new wells further drilled in the production area.

All sites will comprise of:

1. Two 1000 bbl storage tanks for two days crude oil production storage capacity heating provided externally through a fired heater fuelled by associated gas. More tanks would be used if high production rates are sustainable.
2. 320-305-120 type or 228-256-100 type, API American designed beam pump.

3. 30 HP electric motor with control box and 15 minute timer.
4. 0.5 MMBTU gas fired Heater Treater with 75 bbl capacity to act as low pressure separator for associated gas and oil
5. Various flowlines, manifolds and fixed circulating loading facility
6. Two 100 KVA Generator 200 liter diesel storage tank.

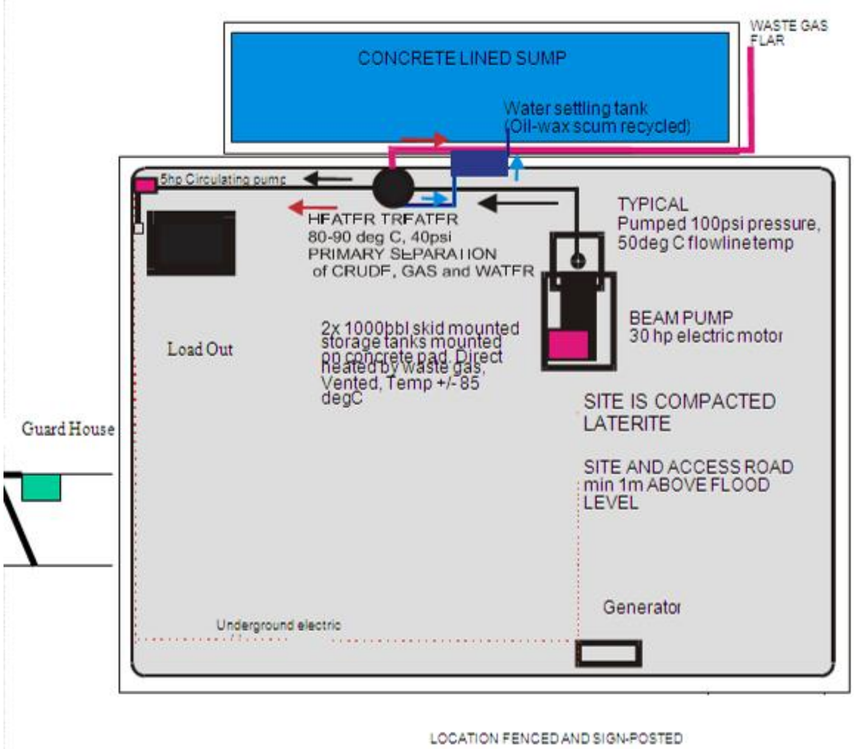

Figure 3.2 Surface facility

3.1.2 Production Process

The process starts from down hole liquid is pumped up by artificial lift to well head. Then, it flows directly to the separator. Gas is separated, and flared for safety purpose. Oil is stored in oil stocktank waiting for transportation by trailer. Water is stored in water stocktank waiting for re-injected to disposal well.

The process was designed for simply producing crude oil. Almost every production process for each well is similar to the process showed in Figure 3.3. However, there are minimal differences in type of equipment which depends on suitability of production condition. For example, certain wells which yield high oil production rate, ESP was installed instead of beam pump. In certain well sites, associated gas is used as fuel for boiler which heated oil in order to maintain oil temperature higher than pour point.

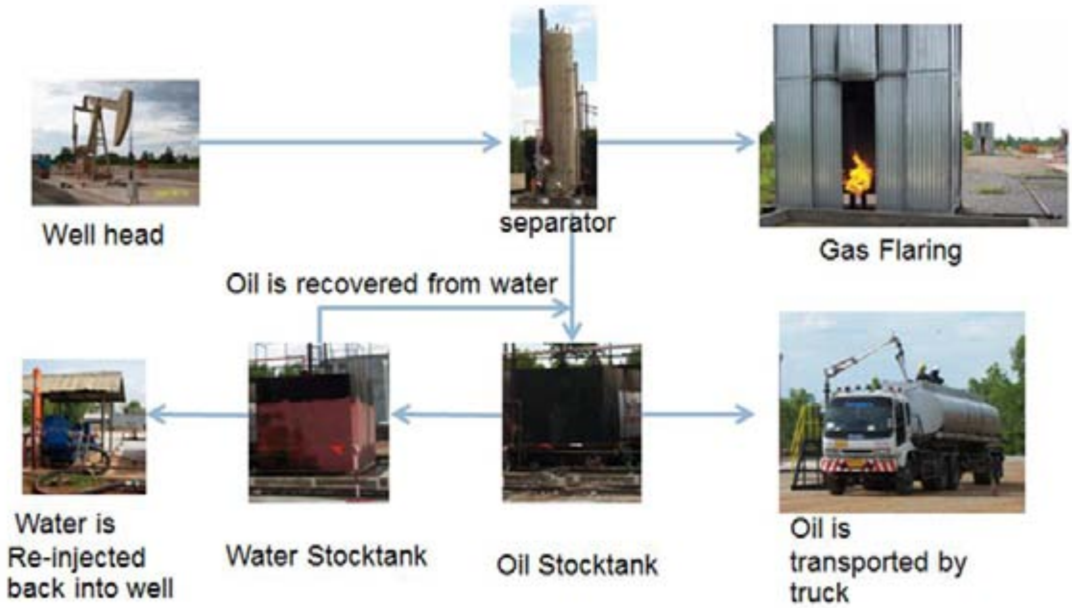

Figure 3.3 Prodcution Process

3.2 Field Geologic and Reservoir detail

The field basin is a Tertiary transtensional inter-montane basin located some 200 km north of Bangkok within the late Palaeozoic Loei-Sukhothai fold belt. This Sub-basin, and the other elements of the Phetchabun Basin, formed from late Oligocene and early Miocene through Pliocene time in response to stresses imparted by the collision of India with the Asian continent. The easterly extrusion of the Chinese/Tibetan blocks imparted a dextral shear on the principal NW-SE fault sets and a sinistral shear on the conjugate NE-SW fault sets.

The Sub-basin takes the form of a half graben with prominent N-S trending basement faults and bounded by NW-SE oriented transfer elements. The Tertiary sedimentary section is also observed to thin gradually to the west. Although the majority of the faulting recognized is vertical to sub-vertical with obvious wrench-related structuring and local reversal of the general westerly thinning.

3.2.1 Geological Structure

The geological structure of this field comprises a series of upthrown dip closures against a major North-South trending westwards heading intrabasinal fault. Figures 4 show the structure map over the field at top upper volcanic interval. Closure to the West is against the major basin fault which close to the South and West, except in the case of the compartment, is generally defined by structural dip. In the case of compartment closure to the South is defined by a West-East trending cross fault. At compartment closure to the East is dip controlled.

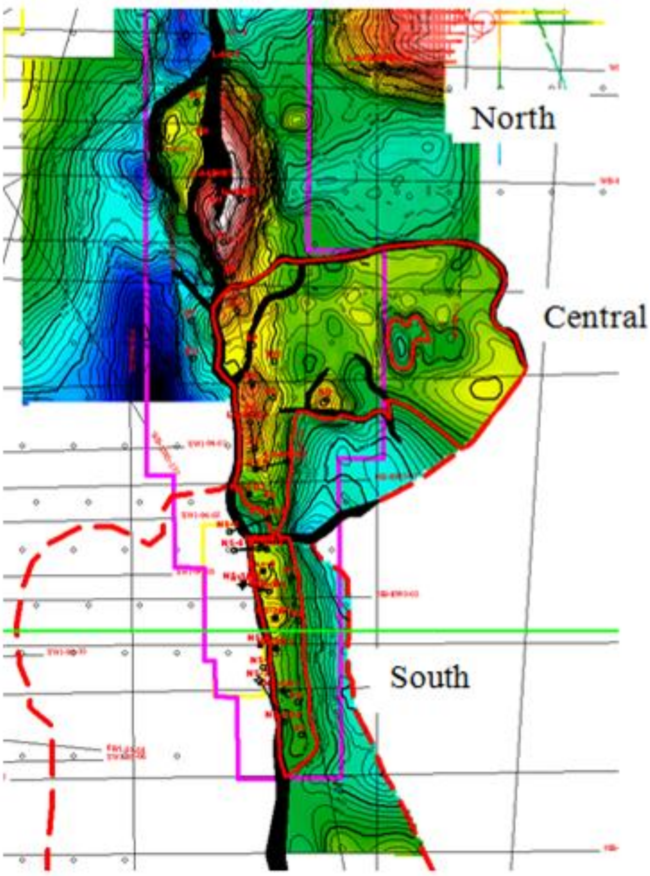

Figure 3.4 North West – South East intrabasinal fault and oil accumulations

3.2.2 Oil Accumulations

This oilfield contains three genetically related oil accumulations (see Figure 3.4) that share the same primary reservoir- fractured Miocene Volcanic, source, seal, timing and oil type. The oil accumulations can be separated as follows:

The Southern Pool

The Southern Pool is an oil accumulation on the upthrown side of the major North-South trending fault. It is defined to the north by minor Northeast-Southwest cross fault, mapped in structural closure, and encloses a mapped areal closure of between 1.57 km^2 and 3.65 km^2.

The Central Pool

The Central Pool is separated from the Southern Pool. It is not certain whether the separating fault is sealing or not and the fault becomes less important north eastwards. It encloses a mapped areal closure of between 2.68km^2 and 5.96km^2.

The Northern Pool

The Northern pool was proved up by the drilled exploration well, located nine kilometers north of the production well. This well proves up the Northerly extension of the oil bearing reservoir, and encloses a mapped areal closure of between 0.15km^2 and 3.7km^2. The oil pool is separated from the Central pool by a North East – South West crossfault.

3.2.3 Reservoir type, quality, and uncertainties

Crude Oil Production has been established by the operator from a volcanic reservoir type first tested in 1997. The first well was drilled on the downthrown side of a major North South intra-basinal fault. The well watered out quickly on test as a result of technical problems, and the play type was abandoned by the subsequent operator.

The current operator drilled two unsuccessful wells into this downthrown feature early in 2007. However, These wells were followed by another well which successfully tested oil, but with a gradually increasing water cut. Adjustments to the well chokes and method of production have allowed water free production to be established from the well at a rate of 320 bopd.

3.2.4 Reservoir Formation

There are a four volcanic intervals. Petrophysics evident indicates significant fracture porosity in the upper three of these intervals. Additionally, there is a tuffaceous horizon overlying the upper volcanic interval encountered in the wells on the upthrown side of the fault, which also indicates possible hydrocarbons from logs. The Upper volcanic and second volcanic were tested, with oil flow being established only for a short period from the Upper interval.

Current operator has subsequently drilled some development wells targeting the upper volcanic reservoir on the upthrown side of the fault, and into the next fault north compartment, targeting the same interval. The exploration wells were also drilled at the North end of the structure, and more modest production has also been established in a structurally higher volcanic interval at that location. All of the wells have successfully produced from the upper volcanic reservoir with a direct correlation between magnitude of productivity and strength of amplitude anomaly.

The data gives a useful insight to the unconventional nature of the reservoirs, which were classified to four volcanic intervals as follow:

Upper Volcanic Reservoir (Current zone producing)

The Upper Volcanic unit appears to comprise two separate bodies of igneous rock. The upper sub-unit is largely clastic in origin, and the lower sub-unit is clearly an intrusive dolerite. The origin of the clastic upper sub-unit remains unknown on the basis of the available data. However, the intrusion of the dolerite may have caused brecciation of the overlying sedimentary rocks. The laminar structure in the lower part of the body may represent rhythmic igneous layering, formed by changes in the mineral mode over thicknesses of meters, which is not uncommon in intrusions, but rarely seen in lava flows.

Volcanic Interval 2

The drilled cuttings of Volcanic Interval 2 are medium/fine grained. The igneous rocks are noticeably altered, with much of the olivine altered to aggregates of deep blue-green chlorite. Pyroxene is thinly scattered, and the large ophitic grains seen in the lower part of unit 1 are absent. The top of the unit appears highly fractured on the CBL image. The rest of the unit is a planar base and largely unfracture. The grain size of the igneous rocks is not inconsistent with an extrusive origin. The fractured top may represent the brecciated, fractured surface of a lava flow. If so, the fracturing may be consistent over the lateral extent of the unit.

Volcanic Interval 3

The medium/fine grain size of the cuttings from Volcanic Interval 3 are not inconsistent with an extrusive origin. The presence of a high fracture density only in the uppermost parts of the unit may also represent a brecciated, fractured surface of a lava flow. There is a presence of a minor silty intercalation. If extrusive in origin, the fracture pattern should be consistent over the lateral extent of the unit.

Volcanic Interval 4

The origin of the sub-spherical structures as evidenced by the CBL log in volcanic interval 4 is enigmatic. There are two possibilities: (1) spheroidal weathering patterns - this would require a significant period of exposure of this unit to weathering agents.(2) Pillow structures – usually only formed by eruption of basalt into water, pillow basalts are normally associated with sub-marine eruptive events. However, such structures are known to form as the result of the flow of sub aerial lavas into lakes and glacial melt water. The existence of pillow basalt would therefore not be inconsistent with the lacustrine origin of the underlying sedimentary rocks. If these structures are pillow basalts, then significant amounts of intercalated hyaloclastite (poorly sorted mixture of basalt fragments and volcanic glass altered to clays) would be expected. The yield of 40% ―claystone” from cuttings at 1380 m may represent such an association. However, the grain size of the cuttings may be too coarse for pillow basalt, and no good examples of glassy chilled margins have been observed.

3.3 Well Behavior

According to field data of the oilfield, There are some characteristics of the production behavior which can be summarized as follows:

1. High variable flowrate
2. Sharp production decline rate

3. Uncertain well production life

The gas utilization project will be planed accordingly with consideration of these factors.

3.4 Gas Composition and Properties

The associated gas from this oilfield is composed mainly of methane (66%) with zero hydrogen sulphide and very low CO_2 as detailed in Table 3.1. Heating value is equal to 1728 BTU/scf.

Table 3.1 Composition and Heating Value of Associated Gas

Compound	Mole (%) y_i	Heating Value (BTU/scf) H_i	Gross Heating Value (BTU/scf) y_i x H_i
C_1-Methanes	0.6634	1010	670.03
C_2-Ethanes	0.0685	1769.6	121.22
C_3-Propanes	0.0917	2516.1	230.73
i-C_4-Iso-butanes	0.0283	3251.9	92.03
n-C_4-N-butanes	0.0481	3262.3	156.92
i-C_5-i-Pentanes	0.0209	4000.9	83.62
n-C_5-n-Pentane	0.0191	4008.9	76.57
C_6-Hexanes	0.0292	4755.9	138.87
C_7-Heptanes	0.0139	5502.5	76.48
C_8-Octanes	0.0073	6248.9	45.62
C_9-Nonanes	0.0035	6996.5	24.49
C_{10}-Decanes	0.0015	7742.9	11.61
N_2-Nitrogen	0.0038	0	0.00
CO_2-Carbon Dioxide	0.0003	0	0.00
H_2S-Hydrogen Sulphide	0	637.1	0.00
Total	1		1728.19

CHAPTER IV
GAS PRODUCTION FORECAST

Gas production forecast has to be studied in order to predict amount of associated gas in the future. Thereafter, the prediction result will be used for considering suitable gas utilization option.

In this chapter, gas production forecast and gas reserve will be studied by using Decline Curve Analysis (DCA) method. There are some assumptions that has to be applied as follows

- Exponential DCA has been used
- Minimum associated gas required for utilizing is 5,000 scfd.
- Minimum economic limit for oil production is 10 bopd

4.1 Decline Curve Analysis

For DCA, 180 days of oil and gas daily production data were plotted on logarithmic scale and was predicted by using trend line as shown in Figure 4.1.

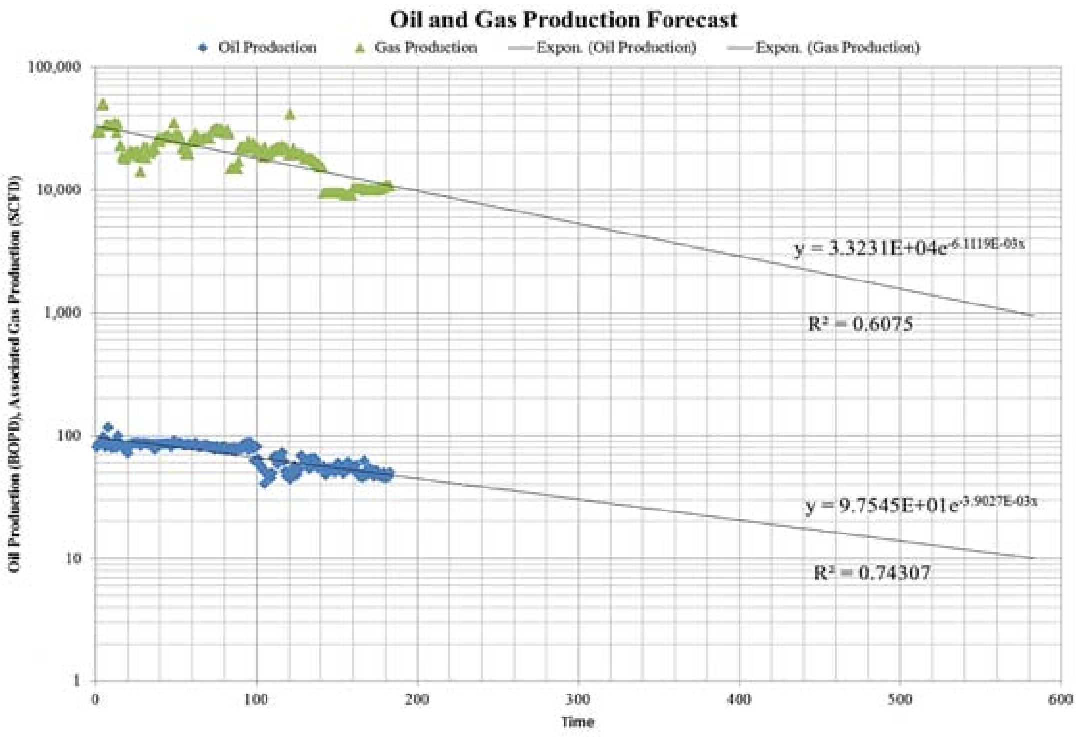

Figure 4.1 Example of exponential DCA

After fitting trend line to the data, the equation of each trend line can be determined.

Gas DCA equation : $y = 33231e^{-0.0061119x}$; $R^2 = 0.6075$

Oil DCA equation : $y = 97.545e^{-0.0033750x}$; $R^2 = 0.74307$

According to Exponential Decline Curve Equation:

$$q = q_i e^{-Dt}$$

These exponential equations variable can be defined as follows

q = production rate at time t, STB/day

qi = production rate at time 0, STB/day

D = nominal exponential decline rate, 1/day

t = time, day

Then, gas and oil production forecast can be performed by substitute number of days to x. When oil production declines below 10 bopd, economic limit is reached and production will be stopped.

4.2 Results

According to Figure 4.1, The last day is is day 180. Production forecast begins from the 181st until the day that oil production rate equals to 10 BOPD. Some parts of production forecast result is shown in Table 4.1.

Table 4.1 Oil and Gas Production Forecast

Day	Forecast Oil Production (BOPD)	Forecast Gas Production (scfd)
181	48.13	10992.68
182	47.94	10925.70
183	47.76	10859.12
184	47.57	10792.95
185	47.39	10727.19
186	47.20	10661.83
187	47.02	10596.86
188	46.83	10532.29
189	46.65	10468.12
190	46.47	10404.33
Continue Production until oil production reach economic limit at 10 BOPD.		
583	10.02	942.00

Table 4.1 shows that oil production will reach economic limit on day 583, which oil and gas production would be 10.02 BOPD and 942 scfd.

Total forecast cumulative oil and gas production from 181 to 583 days are 9,800 stb, and 1,650,000 scf respectively.

By applying this method to each well, we can approximate future gas cumulative production as well as production life from forecast oil production of every well in this oilfield.

Table 4.2 Production Forecast Summary

Well	Production Life (Months)	Gas Reserve (scf)	Oil Reserve (stb)	Average Assoc. Gas Prod. (scfd)	Average Oil Prod. (bopd)	Average GOR (scf/stb)	Comment
A-01	14	N/A	23,420	10,223	129	155	Constant Gas Production
A-02	N/A	N/A	N/A	N/A	N/A	N/A	Shut-in
A-03	5	N/A	3,393	8,088	125	103	Gas Production increased
A-04	15	7,007,330	8,347	27,466.01	39	708	
A-05	29	15,107,639	31,730	27,016	124	264	
A-06	N/A	N/A	N/A	N/A	N/A	N/A	Shut-in
A-07	N/A	N/A	N/A	N/A	N/A	N/A	Shut-in
A-08	10	27,099,624	17,800	203,689	485	512	
A-09	41	6,681,775	26,170	6,362.51	43.63	148.34	
A-10	12	34,285,895	12,236	146,551	157	1,023	
A-11	6	N/A	5,164	12,892	160	112	Constant Gas Production
A-12	13	1,346,958	9,636	20,412	70	289	
A-13	8	N/A	3,113	25,211	20	1,335	Gas Production increased
B-01	10	11,233,937	14,681	52,160	348	194	
B-02	17	N/A	42,826	294,554	599	720	Gas Production increased
B-03	2	N/A	705	172,938	198	1,473	Constant Gas Production
B-04	N/A	N/A	N/A	N/A	N/A	N/A	Shut-in
B-05	N/A	N/A	N/A	N/A	N/A	N/A	Shut-in
B-06	41	N/A	46,586	13,588	112	121	Gas Production is in Plateau Phase
B-07	18	N/A	42,790	38,189	486	105	Gas Production is in Plateau Phase
B-08	N/A	N/A	N/A	25,906	785	34	Oil&Gas Production is in Plateau Phase
B-09	35	N/A	50,996	45,107	185	329	Gas Production is in Plateau Phase

4.3 Discussions

There are some points of the result that needs to be clarified as follows

- There are 2 factors that limit gas utilization life as follows:
    1. Gas utilization stop because oil production has reached economic limit at 10 BOPD.
    2. Gas utilization stop because associated gas production is below 5,000 scfd or minimum utilization system required (See Figure 4.2).
- DCA method is not applicable when production is in plateau period.
- Gas production forecast by DCA method declines faster than actual production.
- According to actual gas data, most of the wells have shared some behaviors namely stable GOR, constant or declined gradually associated gas production. This behavior can be seen on most of the wells in this field (See Figure 4.3).
- There are some wells that have a big swing of GOR and sharp decline of associated gas production. The production profile is shown in Figure 4.4. This kind of well should be avoid for proposing as a gas utilization candidate.
- There are some wells that have an increasing trend of associated gas production as shown in Figure 4.5. For this kind of well, only oil production determines gas utilization life because associated gas production is rising up. This production profile represents the typical solution gas drive reservoir.

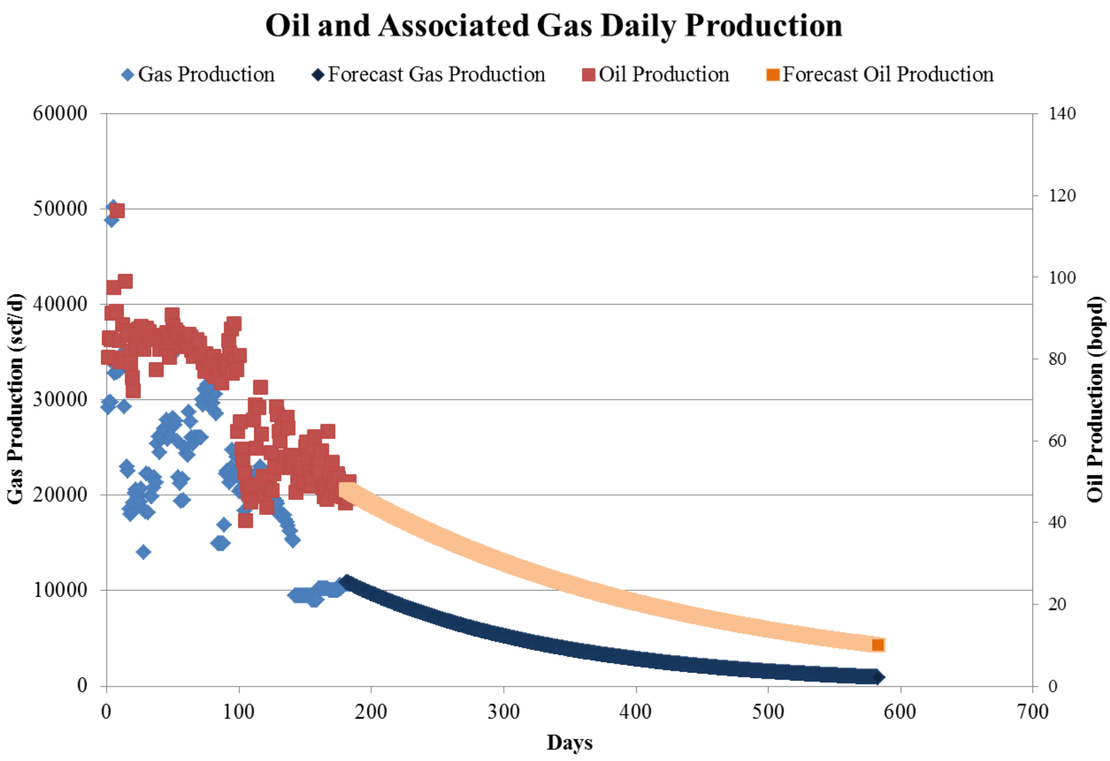

Figure 4.2 Well A-12 Production Forecast

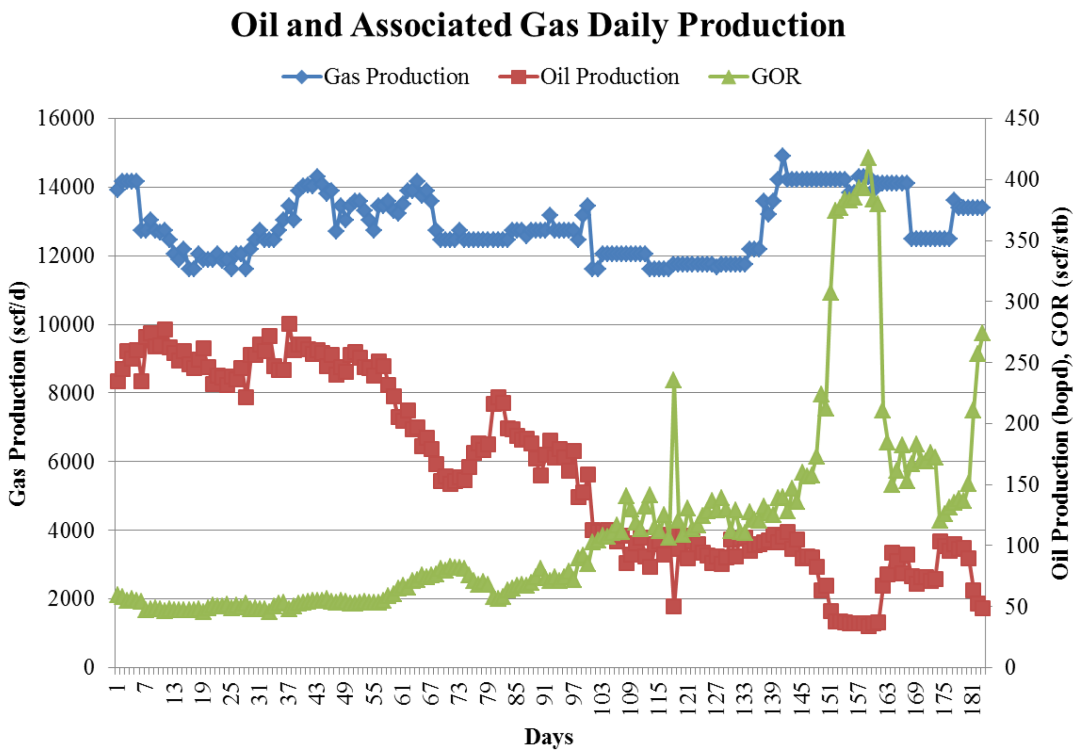

Figure 4.3 Stable Associated Gas Production

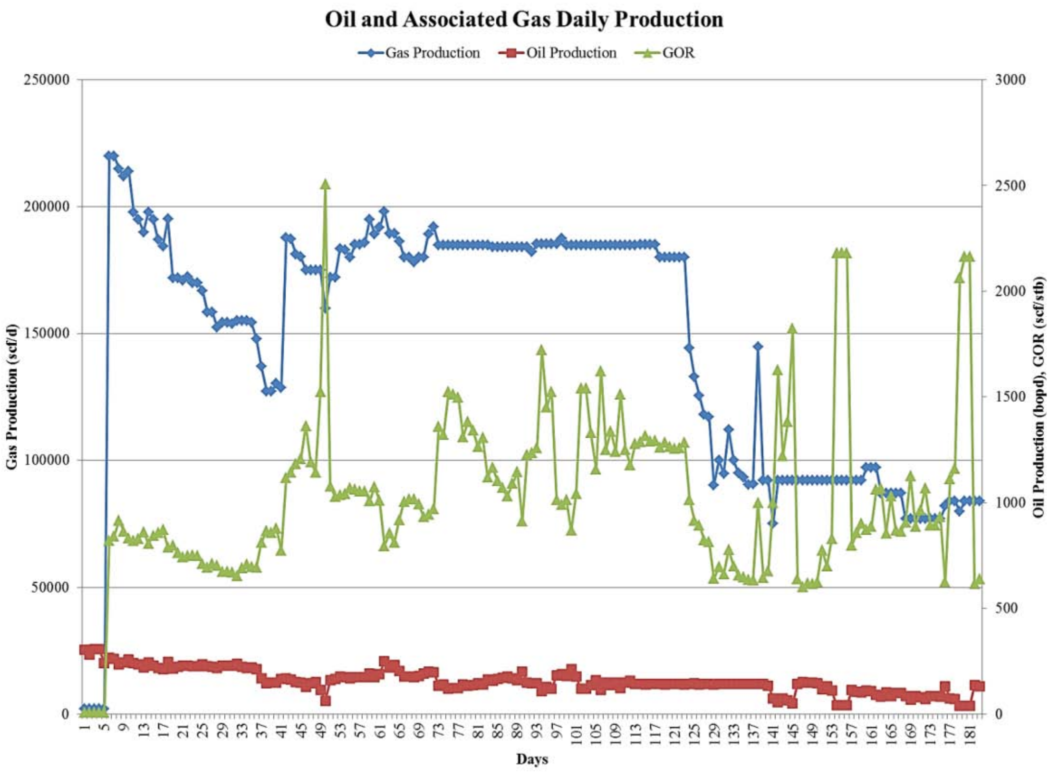

Figure 4.4 Well A-10 Sharp Decline of Gas Production

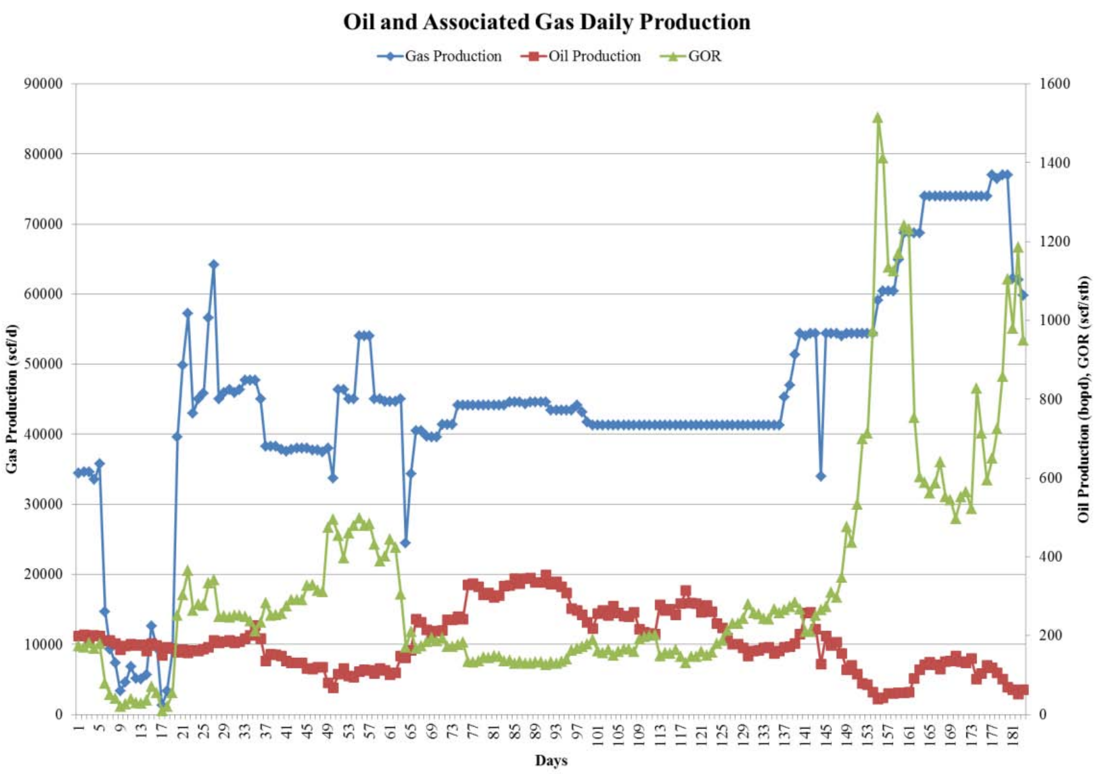

Figure 4.5 Well B-09 Increasing Associated Gas Production

4.4 Conclusions and Recommendations

Most of the wells here showed a stable GOR and associated gas rate with gradually decline over 1 to 2 years, The example of production profile could be seen in Figure 4.5. This well can represent most of the gas and oil production behavior for this oilfield.

However, there are some wells have increasing gas production. If these wells have sufficient associated gas for utilization since the beginning of production, the gas rate would be able to sustain until the end of well life. Therefore, gas utilization life for this kind of well depends on oil production only. When oil production economic limit is reached, the production will be stopped.

There are a few wells that shows sharp gas production decline. Gas utilization options for these wells depend on gas rate. If gas rate falls below gas utilization requirement, the system has to be stopped. These types of wells are not suitable for establishing gas utilization.

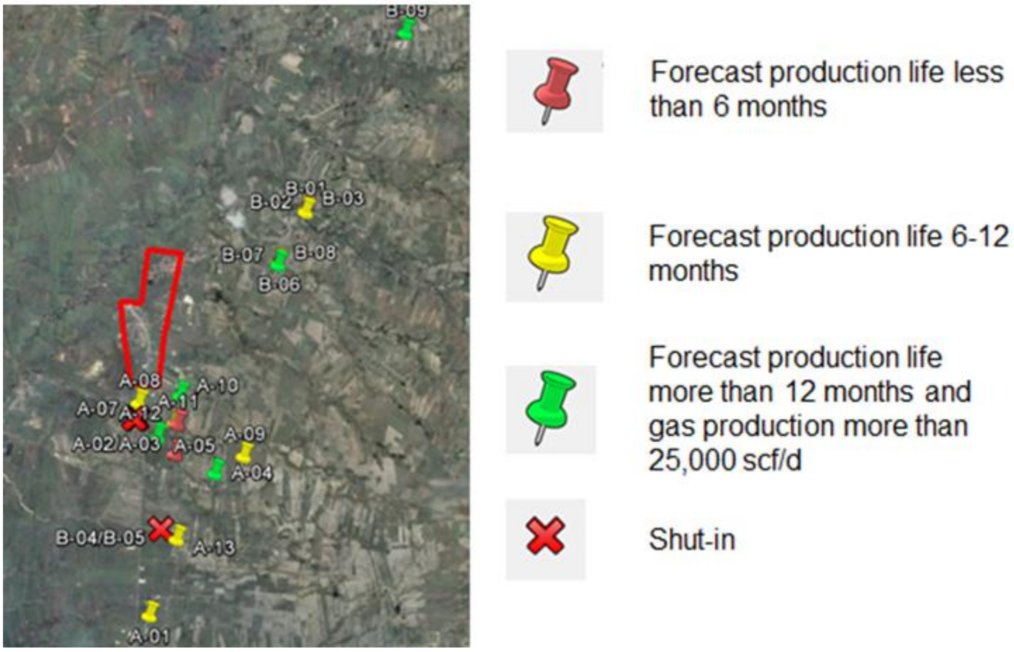

Figure 4.6 Wellsite mapping with production forecast data

To minimize this risk, the candidate wells for flared gas utilization options should have at least 6 months of stable oil and associated gas production. The initial associated gas production rate could expect to be stable in the next 6 months. Therefore, each well should be mapped with the production life data. Figure 4.6 shows the position of each well according to the production forecast data.

CHAPTER V
FEASIBILITY STUDY OF FLARED GAS UTILIZATION

According to chapter III, both surface and subsurface constraints of this oilfield were described. This chapter, which is core chapter of this thesis, will show all processes of feasibility study of flared gas utilization of this unconventional oilfield starting with gas utilization technologies, which will be analyzed for technically feasible, can be considered based on production life and amount of associated gas. Then, each option will be considered through economic feasibility study process in order to determine whether the project is worth for investment. Finally, the option that passes technical and economic feasibility study will be proposed as a flared gas utilization project for this unconventional oilfield.

For environmental aspect, amount of CO_2 emission reduction will be calculated. The result can be used for considering CDM qualification.

5.1 Gas Utilization Options

According to current technology, there are 4 possible technologies that can be used for small-scale gas utilization as follows:

1. Liquefied Natural Gas (LNG)
2. Compressed Natural Gas (CNG)
3. Power Generation
4. On-site Gas Utilization

These 4 options have been widely used for associated gas utilization as per study of the world bank studies, Flared Gas Utilization Strategy Opportunities for Small-Scale Uses of Gas, Indonesia Associated Gas Survey – Screening & Economic Analysis Report.

Regardless of option chosen, pipeline will have to be constructed. Moreover, the pipeline is the main cost of any gas utilization option. It could make any option become feasible or infeasible. Since the pipeline is the main cost, its specification and material properties should be clarified.

5.2 Gas Gathering System

This section will mention about gas gathering system for each gas utilization option. Pipeline and equipment require for gas gathering will be discussed as well as cost estimation for establishing the system.

There are 3 options that require gas gathering system which are:

1. Liquefied Natural Gas (LNG)
2. Compressed Natural Gas (CNG)
3. Power Generation

LNG and CNG plant require associated gas at least 1,000,000 scfd to operate. Since, The daily associated gas production of this field is approximately 1,200,000 scfd. The gas gathering system has to connect every wellsite together in order to collect sufficient gas for the plant.

Power Generation requires associated gas at least 200,000 scfd. These amount of gas can be collect from several wells. The selected wells and plant location will be discussed in section 5.5.1 gas generator technical feasibility study.

5.2.1 Pipeline

Pipeline laying is a major investment, which strongly effects the feasibility of certain gas utilization project. Thus, the process of pipeline laying and pipeline specification has to be reviewed in detailed in order to estimate the reasonable cost.

Figure 5.1 shows the general pattern of pipeline connection for delivering the gas. The numbers marked in the diagram describe each component function as follows:

1. Conventional gas flared pipe
2. Safety valve
3. Split pipe : pipe that connected between flared pipe to surge drum
4. Surge drum : for gas pressure and temperature stabilization
5. 1-5 km pipeline behind surge drum. Compressor might be needed if the gas pressure is not enough.
6. Blower : for rising pressure up and blowing the gas to gas tank
7. Gate valve : prevent back flow

8. Gas tank
9. Gas is delivered to customer

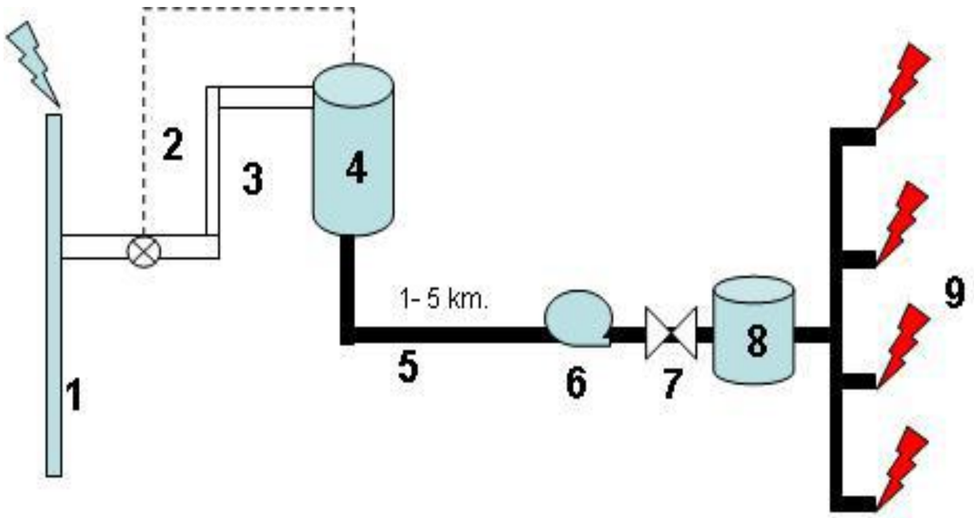

Figure 5.1 Schematic Diagram of Natural Gas Pipeline

Gas Pipeline Specification

Generally, metal pipeline has been widely used in petroleum industry due to safety and durability. However, the tradeoff of using metal pipe is the high material price cost. The cost estimation of 6 inch diameter metal pipe is around 10 million baht per 1 km. Thus, the small-scale gas utilization project, for example 1 MW gas power plant, would require too long time or unable to reach breakeven point with this high pipeline cost. By the way, small-scale projects that transmit low pressure gas have an option of using polyethylene (PE) plastic material. This material qualification is durability with installation and moving are comfortable, in addition, lower maintenance cost than metal pipe. According to the World Bank study "Indonesia Associated Gas Survey – Screening & Economic Analysis Report", the cost of PE pipe is 60% of metal pipe or 6 million baht per 1 km. The used PE pipe was HDPE (High Density Polyethylene) that has high quality, up to 20 bar (290 psi) working pressure, and -40 –80 º Celsius working temperature with the range of 16 – 1,600 mm. diameter and HDPE grading following plastic raw material for instance PE63, PE80, and PE100. Natural gas HDPE pipe installation for safety must be approximately buried 1 m. depth and showed warning signs clearly along the route of pipeline on the ground. There are 2 ways of pipe installation, open cut and HDD (Horizontal Directional Drilling) as detailed shown in Figure 5.2.

Table 5.1, 5.2, and 5.3 show physical property of recommended PE gas pipeline.

Table 5.1 Property of PE pipeline

Qualification	Nominal value	Unit
Specific Gravity	950 – 965	kg/m^3
Yield Strength	18 – 24	kg/cm^2
Elongation at break	> 600	%
Hardness (Shore D)	55 – 70	
Thermal Conductivity	0.4 – 0.5	W/m ^{o} K
Heat Capacity	2.25	kj/kg ^{o} K
Melting Temperature	135	^{o} C
Young's Modulus	400 – 1000	N/mm^2
Flash Point	> 340	^{o} C
Thermal expansion coefficient	17 x 10-5	cm/cm ^{o} K

Table 5.2 comparing properties of pipe

Properties	PE Pipe	PVC Pipe	Stainless Pipe
Weight	Light	Light	Heavier than HDPE, 5 times of PVC
Transportation	Large amount, comfortable, smaller can be placed in the bigger one and rolled for transport	Same as PE (HDPE), but cannot be rolled	Heavy material, moving and carrying equipment needed
Curving	25-40 times of pipe diameter	Cannot	Cannot
Flow coefficient	C = 150	C = 150	C = 100

Table 5.3 Comparing properties of pipe

Properties	PE Pipe	PVC Pipe	Stainless Pipe
Max. working pressure	16 kg / cm^2	13.5 kg / cm^2	50 kg / cm^2
Max. working temperature	- 40°C to 80°C	0°C to 60°C	100°C to 300°C
Working Life	More than 50 years	10 - 20 years	10 - 30 years
Corrosion Durability	No rust	Same as PE (HDPE)	Have chance for rust
Chemical Durability	Yes, both acid and base	Same as PE (HDPE) except some solution	No
Underground Installation	Connect on the ground, then lay in the route	Normally connect in the route	Moving and carrying equipment needed, and wider route to make connecting there
Transportation and installation cost comparing to pipe cost (not including others equipments such as valve, etc.)	10%	10%	30%
Connection	Butt welding, pipes completely connected together and no leak	Joint, but leaking chance	Flange, but expensive

Step 1

Announce the project
to the public

Step 2

Open the soil
through survey route

Step 3

Make a wall to prevent
the ruining case

Step 4

Clear the route
for laying the pipe

Step 5

Lay the pipe

Step 6

Stringing the pipe
to get the desired length

Step 7

Cover by concrete slab & warning tape
(Open-cut method)

Step 8

Reinstatement and install the warning sign
along the route

Figure 5.2 Pipe Laying Process

5.2.2 Gas gathering system for LNG and CNG plant

LNG and CNG plant requires at least 1,000,000 scfd of associated gas. This amount of gas is equal to gas production for the whole field. Therefore, the plant should be built as a central processing plant, which receives gas from gas gathering system that collects gas from every well.

The location for central processing plant should be 5 km southwest to the city next to the main road for transportation reason. Figure 5.3 shows the pipeline laying path that connected every well to the plant. The main pipeline has to be approximately 15 km long.

The 5 km yellow line is planned for gathering gas from southern zone of the field, and the 10 km blue line is for gathering gas from northern zone. Both yellow and blue line have to be equipped with gas compressors.

The compressor installation and operating cost are based on the estimation of World Bank study, ―Indonesia Associated Gas Survey – Screening & Economic Analysis Report”. This gathering system is expected to gather 1,300,000 scfd of associated gas. The installed cost for compression is approximately 15,000,000 Baht and the annual Operating and Maintenance (O&M) cost of this system is assumed to be 5% of capital cost or 750,000 Baht per year.

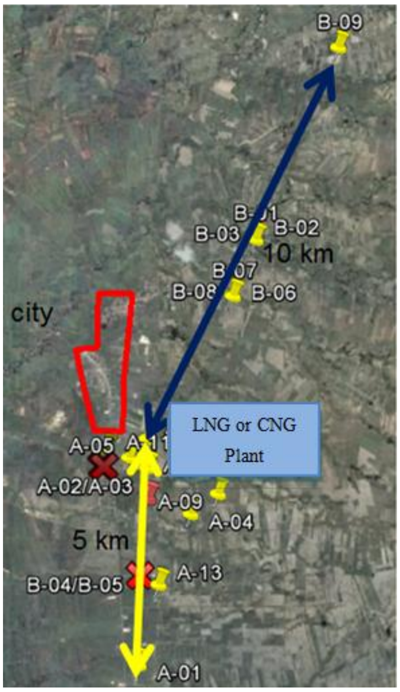

Figure 5.3 Pipeline Laying Path and LNG plant position

The cost of gas gathering system for LNG or CNG plant can be summarized as follows:

Table 5.4 Gas Gathering System Investment

Gas Gathering System Investment	Estimated Cost (Baht)
15 km PE pipeline laying	90,000,000
Compressor Installed Cost	15,000,000
Total	105,000,000

In addition, there is also O&M cost, which is 750,000 Baht annually. This baseline gas gathering system cost will be used for economic analysis in LNG and CNG.

5.3 Liquefied Natural Gas (LNG) Opiton

LNG is an efficient way to utilize gas. However, it requires certain amount of gas feed, which will be analyzed in technical feasibility section as well as the suitable position to build the LNG plant.

The small-scale LNG plant requires at least 1,000,000 scfd of gas feed to give LNG production 10 tons/day of LNG. This amount of gas can be only obtained by connecting every well in this oilfield together. However, the associated gas production from almost every well would not sustain longer than 2 years according to production forecast data.

The LNG plant needs gas from the whole field, which is collected by gas gathering system mentioned on section 5.2. The cost of the system is shown in Table 5.4.

Small-scale LNG economic feasibility is studied in detailed by Noppanan Nopsiri in 2009. The cost estimated for LNG plant can be referred to this study. However, this thesis is studied in 2010 – 2012, the cost is assumed to be increased by 15%. LNG cost can be assumed as follows:

- Gas gathering system is 105,000,000 Baht and O&M is 750,000 Bath annually as per Table 5.4
- The LNG plant needs 140,000,000 Baht for the plant investment
- 1,000,0000 scfd of gas feed to LNG production give 10 tons/day of LNG
- LNG plant O&M is 1,000,000 Baht per 1 mmscfd gas processed per month or 12,000,000 Baht annually
- Working day 350 days/year
- LNG price 10.5 baht/kg
- Depreciation: Straight line 33 % over 3 years project life without salvage value and capital gain
- Associated gas will be fed to the plant according to the gas production forecast. The gas is sufficient to feed the plant for 3 years with 1.2 mmscfd for the first 2 years and 1 mmscfd for the third year.

By this assumption, the cash flow analysis can be performed. According to Table 5.5, NPV is -165 million Baht at the end of project life. The annual net income of this project is equal to the revenue subtract the O&M cost, which is approximately 32 million Baht, around 12.6% of capital cost. Even the yearly income is high, but the project life is only 3 years, which is too short to recover the capital investment cost and make the project economically feasible. The key factor is the amount of associated gas and the production life at this marginal field, which is too small to establish LNG plant. With current condition, the project will never be able to make positive NPV.

Table 5.5 LNG Cash Flow

Year No.	Gas Daily Production @ the end of the year (MMSCFD)	Gas Gathering System	Liquification Facilities (Baht)	LNG Producer Capital Expense (Baht)	Annual Gas Avaliable (MMSCF/Year)	Annual LNG Sale (ton/Year)	LNG Revenue (Baht)	LNG Operation & Maintenance Expense (Baht)	LNG Straight Line Depreciation (Baht)	LNG Taxable Income (Baht)	LNG 30% Income Tax (Baht)
0	1.2	105,000,000	140,000,000	245,000,000	420	4,200	44,100,000	12,750,000	81,665,850	-50,315,850	0
1	1.2				420	4,200	44,100,000	12,750,000	81,665,850	-50,315,850	0
2	1.0				350	3,500	36,750,000	12,750,000	81,665,850	-57,665,850	0
Total					1,190	11,900	124,950,000	38,250,000	244,997,550	-158,297,550	0

Table 5.5 LNG Cash Flow (continue)

LNG Net Income After Tax (Baht)	LNG Cash Flow (Baht)	LNG 10 % Discount Cash Flow (Baht)	LNG Cumulative Discount Cash Flow (Baht)
-50,315,850	-213,650,000	-213,650,000	-213,650,000
-50,315,850	31,350,000	28,500,000	-185,150,000
-57,665,850	24,000,000	19,834,711	-165,315,289
-158,297,550	-158,300,000	-165,315,289	

5.4 Compressed Natural Gas Option (CNG)

CNG is well known and widely used gas utilization option. For technical feasibility, CNG requires approximately same amount of gas feed as LNG. The plant position should be easy access as well as be center of the gas pipeline network. Therefore, the plant position should be at the same position as LNG option.

In term of economic aspect, Generally, CNG requires larger investment than LNG. If LNG is not economic feasible with this oilfield condition, CNG is not economic feasible too. However, CNG technical and economic data will be approximated and shown here for future consideration.

According to World Bank Study, CNG plant could be run with at least 1,200,000 scfd of gas feed. To obtain this amount of gas, every wellsite has to be connected together. The CNG assumptions are listed and describe as follows:

- Gas gathering system is 105,000,000 Baht and O&M is 750,000 Bath annually as per Table 5.4
- Entry end metering and pressure & flow control is assumed to cost 1,500,000 Baht/mmscfd.
- High pressure compressor is require to pressurizes gas to approximately 3,000 psi. This requires additional compression. The cost of CNG compression facility is assumed to be 15,000,000 Baht per 1 mmscfd capacity and O&M cost is 700,000 Baht/year
- The cost for CNG storage facility is assumed to be 30,000,000 Baht per 1 mmscfd. It is assumed that 1 day storage is required at the production site.
- Other CNG facility is assumed to be 50,000,000 Baht. This involved the construction site preparation, landfilled, office building, warehouse, etc.
- CNG processing facility O&M is 12,000,000 Baht annually
- Working day 350 days/year
- 1,2000,000 mmscfd of gas feed to CNG production give 16 tons/day of CNG
- CNG price is 10.50 baht/kg
- Depreciation: Straight line 33 % over 3 years project life without salvage value and capital gain

- Associated gas will be fed to the plant according to the gas production forecast. The gas is sufficient to feed the plant for 3 years with 1.2 mmscfd for the first 2 years and 1 mmscfd for the third year.

By this assumption, the cash flow can be presented as per Table 5.6. The NPV is -123 million Baht at the end of project life. The annual net income of the project is around 30 million Baht or 15% of capital cost, which is quite high. However, the project life is only 3 years, which is too short which is too short to recover the capital investment cost and make the project economically feasible. The key factor is the amount of associated gas and the production life at this marginal field, which is too small to establish CNG plant. With current condition, the project will never be able to make positive NPV.

Table 5.6 CNG Cash Flow

Year No.	Gas Daily Production @ the end of the year (MMSCFD)	Gas gathering System	CNG Plant Facility (Include High Pressure Compressor)	CNG Capital Expense (Baht)	Annual Gas Available (MMSCF/Year)	Annual CNG Sale (ton/Year)	CNG Revenue (Baht)	CNG Operation & Maintenance Expense (Baht)	CNG Straight Line Depreciation (Baht)	CNG Taxable Income (Baht)	CNG 30% Income Tax (Baht)
0	1.20	105,000,000	96,500,000	201,500,000	420.00	4,200	44,100,000	13,450,000	67,165,995	-36,515,995	0
1	1.20				420.00	4,200	44,100,000	13,450,000	67,165,995	-36,515,995	0
2	1.00				350.00	3,500	36,750,000	13,450,000	67,165,995	-43,865,995	0
Total					1,190	11,900	124,950,000	40,350,000	201,497,985	-116,897,985	0

Table 5.6 CNG Cash Flow (Continue)

CNG Net Income After Tax (Baht)	CNG Cash Flow (Baht)	CNG 10 % Discount Cash Flow (Baht)
-36,515,995	-170,850,000	-170,850,000
-36,515,995	30,650,000	27,863,636
-43,865,995	23,300,000	19,256,198
-116,897,985	-116,900,000	-123,730,165

5.5 Natural Gas Electric Generator Option

Electric generator is a conventional way to utilize the gas. In this section, feasibility study will start from making a technical feasibility. Then, if this project is technically feasible, it will be studied further in cost analysis and economic model.

Technically, 1 MW gas generator needs at least 200,000 scfd. There are only certain wells that appropriate for selecting as sources of gas utilization. If the gas level drop below 200,000 scfd. the generator would stop working.

Currently, there is no existing infrastructure in place to gather the low pressure raw untreated gas into a central pool. The crude oil stabilization process is wellsite based. A heavy investment in permanent infield gathering pipelines would be required to link certain individual wellsite to a grid to utilize any gas surplus to the existing crude oil stabilization process, and transport the gas to a central processing plant. Compression would also be required due to the very low pressure of the gas at the wellhead.

Figures 5.4 shows a prospect group of wells that should be selected for gas utilization. There are 2 group of wells in the north part of the oilfield. The first group consists of well B-01, B-02, and B-03. This group has 200,000 scfd of gas production with 24 months of forecast production life. This amount of gas just meets the minimum requirement of the generator. However, there must be more gas feed to this plant to guarantee sufficient amount of gas supply.

Therefore, well B-06, B-07, and B-08, which located 1.5 km southwest of the first group, are taken into consideration. This group has total associated gas production of 75,000 scfd with 22 months production forecast.

After combine these 2 groups of wells, there will be 275,000 scfd gas supply, which is enough for smoothly running an 1 MW generator.

The cost of pipeline laying, and O&M for connecting these 2 wells is estimated to be 20,000,000 Baht.

Figure 5.4 Candidate wells with pipeline laying plan

After oil and associated gas are separated in production separator, associated gas evaporates at atmospheric pressure. When gas is to be used for power production, it would normally be compressed to 25–30 bar, while transmission in pipelines would normally require compression to a higher pressure. According to World Bank Study, the cost for field gas compression is 5,000,000 Baht to compress 200,000 scfd

Small power producing units (250–5,000 kW) normally have overall efficiencies of 25–35 percent. According to the chart below, 1 MW generator costs approximately 850,000$ or 25,500,000 Baht

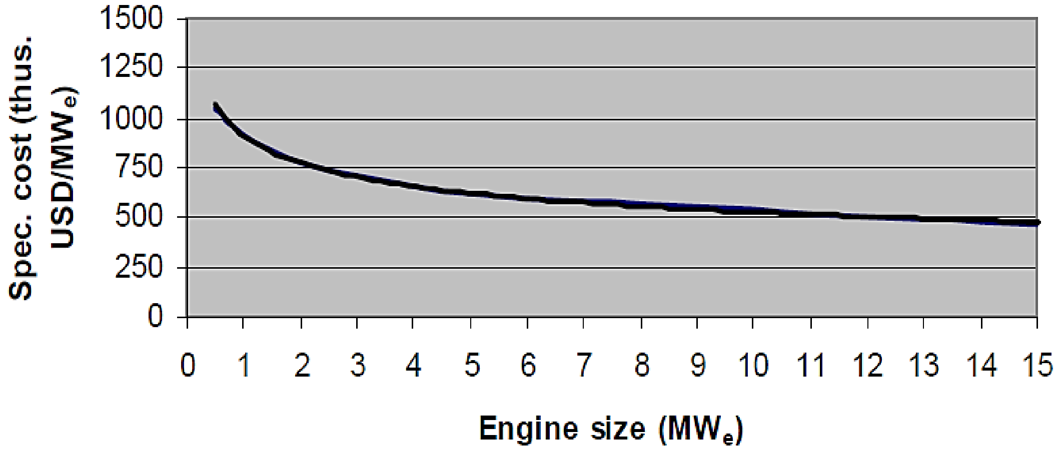

Figure 5.5 Cost curve for engine installations
(Flared Gas Utilization Strategy Opportunities for Small-Scale Uses of Gas, World Bank Group, 2004)

The economic analysis for this option can be referred to study of Nopanan Nopsiri in 2009. However, this thesis is studied in 2010 – 2012, the cost is assumed to be increased by 15%. The assumption of off-site processing plant is as follows:

- 1 MW generator installation and construction cost 25,500,000 Baht
- Pipeline laying cost 20,000,000 Baht
- Field gas compressor cost 5,000,000 Baht
- O&M is 600,000 Baht anually
- Power price 2.6 Baht/kW

- Working day 365 days/year
- Gas consumption of 1 MW power generator is 200,000 scfd
- Depreciation: Straight line 33 % over 3 years project life without salvage value and capital gain

Table 5.7 Gas Generator Cash Flow

Year No.	Gas Daily Production @ the end of the year (MSCFD)	Building, Pipe Laying, Equipment, and Machine Cost (Baht)	Power Production (MW)	Power Plant Revenue (Baht)	Power Plant Operation & Maintenance Expense (Baht)	Power Plant Straight Line Depreciation (Baht)	Power Plant Taxable Income (Baht)	Electricity Seller 15% Income Tax (Baht)
0	200	50,500,000	0.79	14,555,835	600,000	25,250,000	-11,294,165	0
1	200		0.79	14,555,835	600,000	25,250,000	-11,294,165	0
Total			1.58	29,111,670	1,200,000	50,500,000	-22,588,330	0

Table 5.7 Gas Generator Cash Flow (continue)

Power Plant Net Income After Tax (Baht)	Power Plant Cash Flow (Baht)	10 % Discount Cash Flow (Baht)
-11,294,165	-36,544,165	-36,544,165
-11,294,165	13,955,835	12,687,123
-22,588,330	-22,588,330	-23,857,042

The target amount of gas required is 200,000 scfd in order to run 1 MW generator. From this assumption, cash flow can be derived as shown in Table 5.7. At the end of the project, NPV is approximately -24 million Baht, which indicates the project is not economic feasible. If the well life can be extended by with the same gas flowrate for 5 years, the NPV would be positive.

Production history showed fast decline trend of oil production. For example, Figure 5.6 and 5.7 show the sharp decline production history and unexpected sharp production decline. This is one of the behaviors of oil production from volcanic reservoir. From Figure 5.6, the well was shut-in in 8 months earlier than forecast. Every production well in this area has a chance to have analogous behaviors to this example well. Therefore, investing on any high cost infrastructure is a very high risk option. There is no guarantee for sustainable constant oil production for any wells produced from volcanic reservoir. Off-site gas utilization concept should not be implemented at this unconventional oilfield.

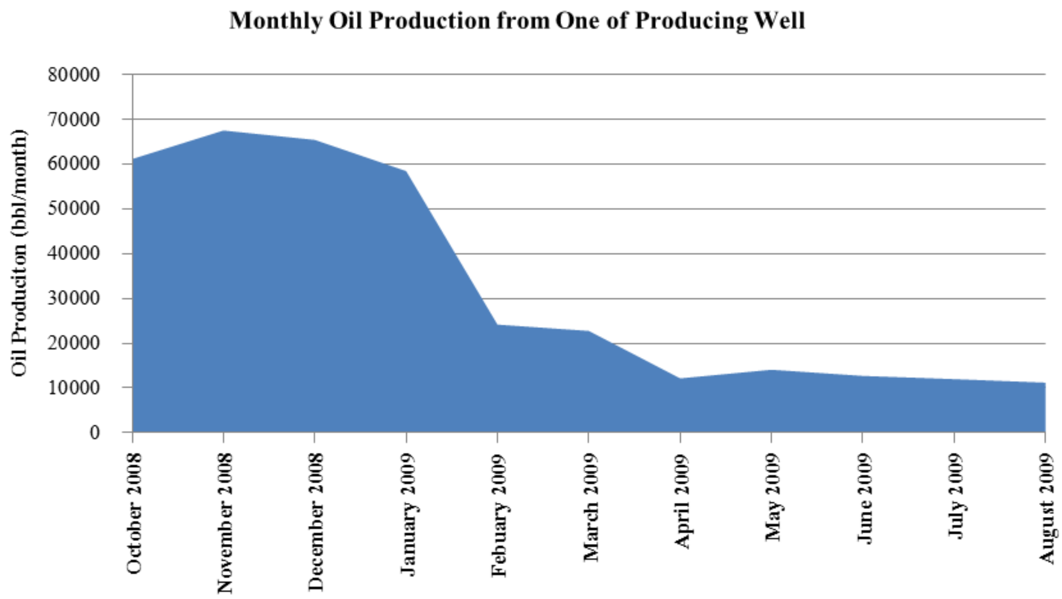

Figure 5.6 Sharp production decline history

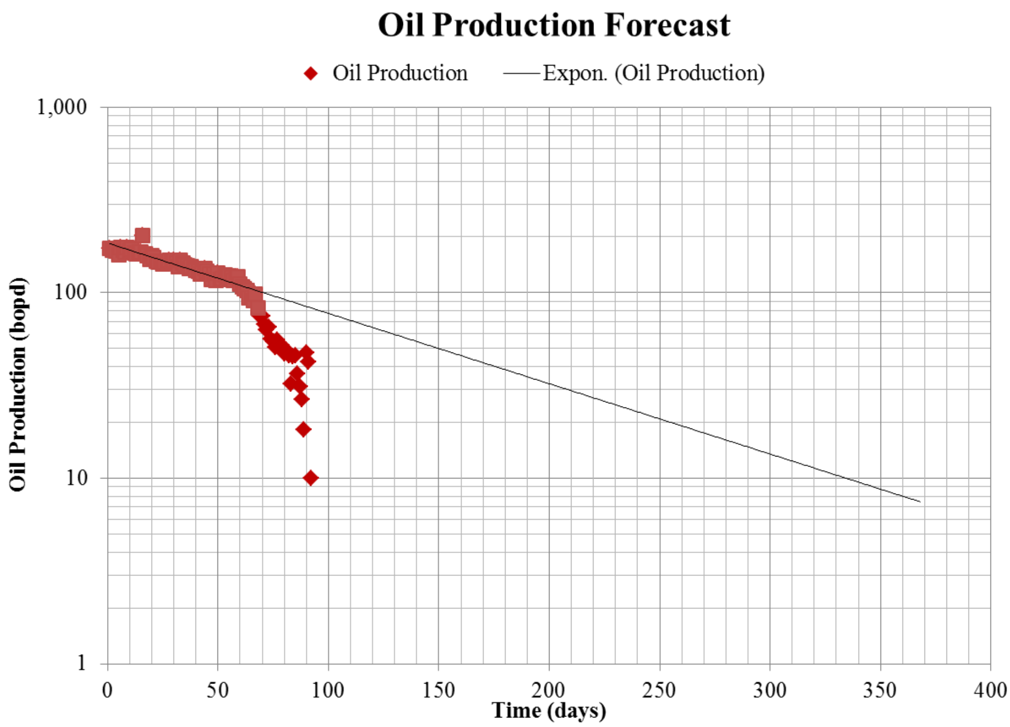

Figure 5.7 Uncertainty of sharp production decline rate

This oilfield has small amount of associated gas as well as the production life is short. It is not feasible to invest on an off-site project that require heavy investment for gas processing plant, gas pipeline. Therefore, the gas should be utilized by other methods

There are 2 main reasons that off-site gas utilization is not feasible. These reason are listed as follows:

1. Not enough associated gas supply until the project reaches positive NPV. This is because of the short production life.
2. If a new well is planned to connect to off-site gas supply system, it requires heavy investment for pipeline construction.
3. The associated gas production per well is too small. Thus, long pipeline has to be constructed to connect the entire oilfield together with 15km North to South

According to these 3 main constraints, the gas utilization option for this field should have characteristics as follows:

1. Be able to quickly reach positive NPV
2. No pipeline required
3. Be able to utilize small amount of gas
4. Be able to mobilize if the well is early abandoned

Therefore, on-site gas utilization is picked for feasibility study because its advantages are likely to compatible with this oilfield constraints.

5.6 On-site gas utilization

In order to make gas utilization correspond with this marginal oil field fracture reservoir, the key recommended concepts of gas utilization project can be summarized as follows:

1. Gas utilization unit should have light weight and high mobility in order to be able to mobilize and hook up at new well at any time.
2. Gas utilization unit should have short payback time for reducing the great risk of early and unpredictable depletion
3. Gas utilization unit should consume gas around 5,000 scfd for gas engine, 8,000 scfd for heater treater, and 15,000 for gas generator for at least 6 months

There are 3 proposed options are chosen as follows:

1. Heater treater
2. Gas engine
3. Gas generator

5.6.1 Heater Treater

Gas utilization project begins with the most common equipment, the heater treater, which is a basic requirement for oil production.

The API vertical heater treater (Figure 5.9) is used:

- to initially de-gas the emulsion as it enters the heater;
- to remove free water as the emulsion enters the internal down-comer before it

- heated
- for washing water and heating of the emulsion as it flows over the fire tubes
- for water drop coalescence and settling.

Due to the uncertainties and unpredictability in productivity and decline rates, the facilities are installed in a manner that allows the majority of the capital plant to be reutilized on other wells.

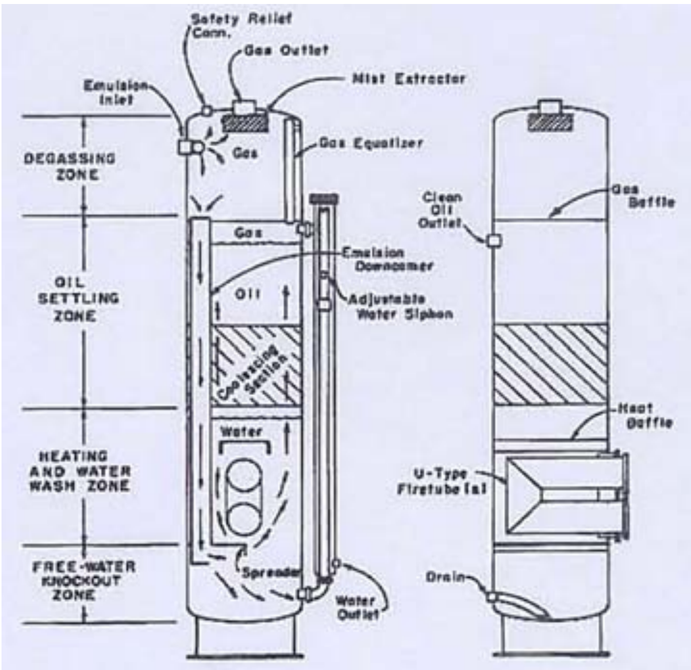

Figure 5.8 Heater Treater Schematic

The standard API heater treater has a maximum design pressure of 50 psig and is operated at a pressure range of 10-15 psig. The heater burner is sized at 500,000 Btu/hr, which is equivalent to a gas consumption of 7,000 scfd at full burn (70%burner efficiency, fuel 1,720 btu/scf, 22.5% excess combustion air as per operation manual, 20%)

Gas collected from the top of the treater is utilized on site to fuel the gas burners on the heater (and any auxiliary tank farm heaters). Initially, excess gas that cannot be utilized on site is released at low pressure to an enclosed ground flare.

Heater treater is necessary equipment for oil production. Thus, the cost of it will not be taken into account as an investment in flared gas utilization project. Moreover, using associated gas as a heater treater fuel will effectively reduce operation cost of this oilfield, because free associated gas will be used instead of buying Liquefied Petroleum Gas (LPG) as fuel of heater treater.

The amount of LPG consumption by heater treater is 190 kg/day. For calculating the benefit of this gas utilization project, these assumptions have been made

1. LPG price is 20 Baht/kg
2. 70% burner efficiency of heater treater

Thus, the cost of running heater treater with LPG is 3,800 Baht/day or 114,000 Baht/month. Substituted LPG with associated gas has a cost of installing pipeline, valve, and pressure regulator around 50,000-100,000 Baht

Payback period of this project is less than a month, because the investment is only 100,000 Baht, while the cost saving per month is 114,000 Baht

In summary, any wells that have gas production more than 7,000 scfd should change heater treater fuel from LPG to associated gas.

5.6.2 On-site Gas Engine

Gas engine will be installed at the well site for directly driving the beam pump instead of diesel engine. The benefit of this is not only reducing diesel fuel cost, but also decrease amount of emission from diesel engine.

For technical feasibility, there are three main steps for changing to gas engine.

1. Select high mobility gas engine that can provide 15 HP
2. Calculate amount of gas consumption for selected engine

If the gas consumption rate is reasonable for applying at this field, economic feasibility study will be performed.

Some production wells in this field have an unexpected sharp production decline, associated gas production would be insufficient for running gas engine. Therefore, gas engine must have options to be powered by either associated gas or gasoline. If the oil production level falls below economic limit, it might result in temporally well shut in or early well abandonment. The proposed gas utilization equipment could be mobilized to another well.

The first consideration over gas engine selection is the engine power, which has to be at least 15 HP. A group of gas engine is selected. Figure 5.10 shows the horse power requirements chart for determine engine model.

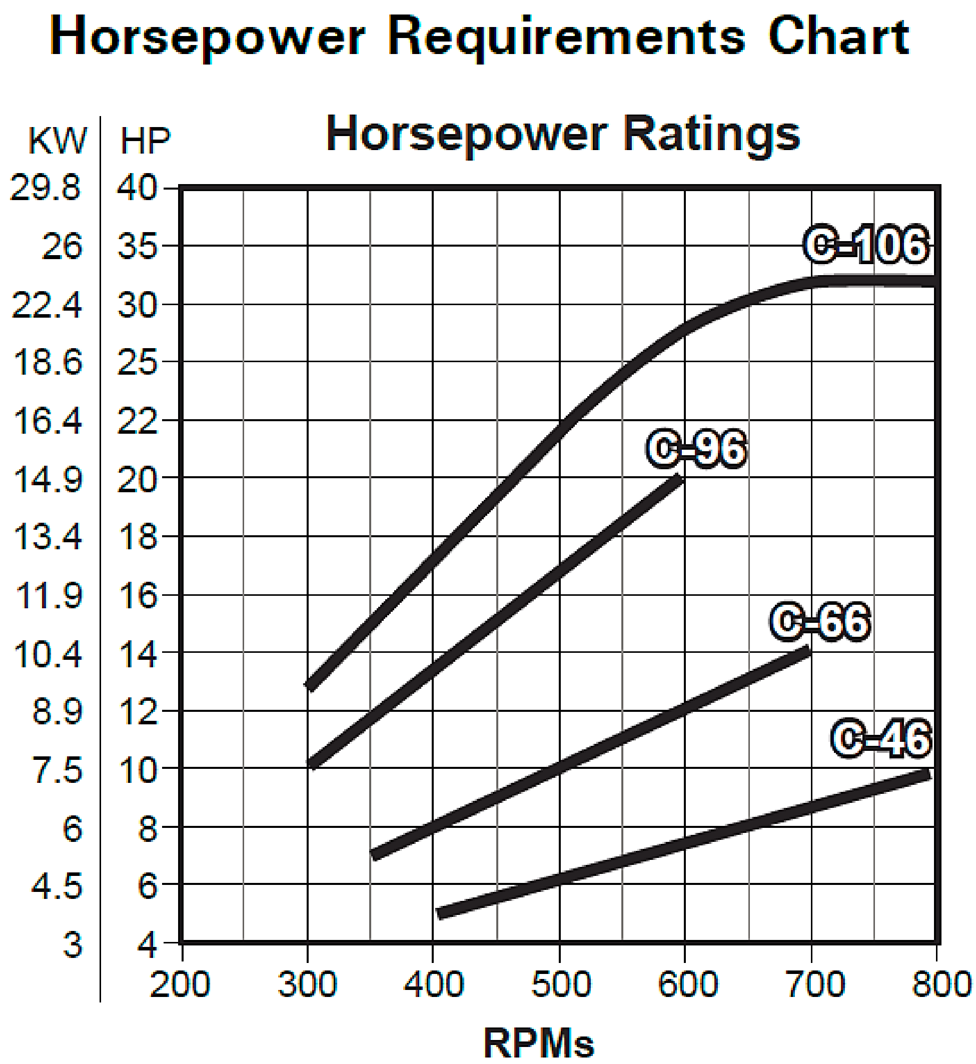

Figure 5.9 Horse Power Requirement Chart
(Operation, Service, and Parts book, Arrow Engine Company, 2010)

From Figure 5.9, the model that suitable for driving 15 HP is C-96 running at 500 RPM. After that, BTU can be determined by next chart.

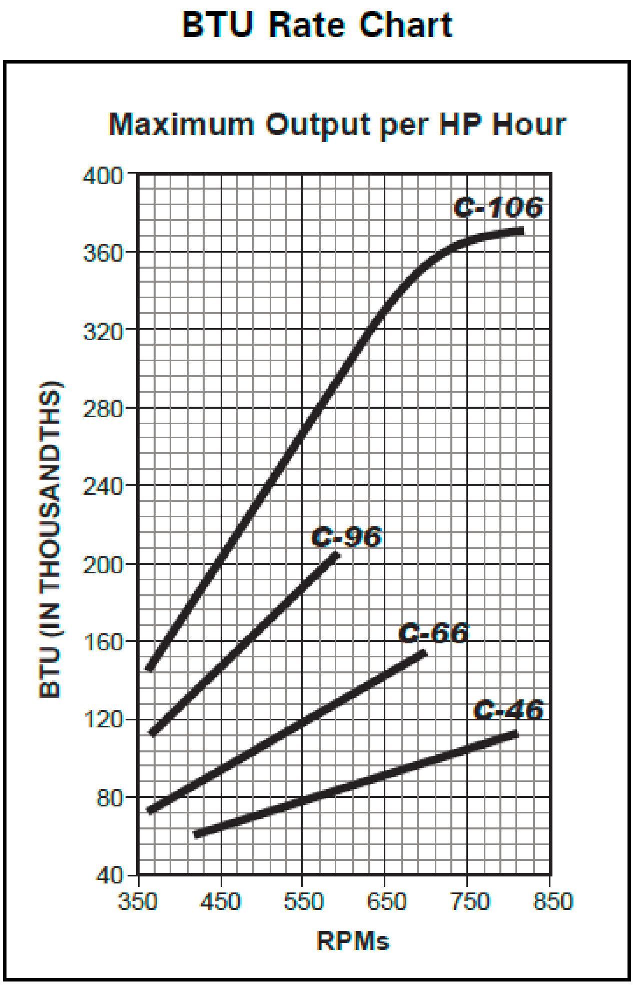

Figure 5.10 BTU rate chart
(Operation, Service, and Parts book, Arrow Engine Company, 2010)

From Figure 5.10, amount of BTU require can be determined. At 500 RPM, output is 180,000 BTU/h. According to Table 3.1, associated gas heating value is 1,728 BTU/scf

For 180,000 BTU/h output, we need 180,000/1,728 which is 104 cu ft/hr or 2,500 cu ft/day. The recommended associated gas production should be at least 5,000 scfd as a margin of safety.

To provide 15 HP for beam pump, C-66 engine is selected, The engine should run at 500 rpm. The, well with associated gas production between 5,000 – 15,000 scfd can be proposed for this option.

Figure 5.11 Single Cylinder Gas Engine

Installing a gas engine is likely to quickly reach payback period, because it will totally replace diesel cost from diesel engine. Therefore, if the energy source is changed to associated gas, it will completely reduce all of diesel fuel cost. The major investment of this gas utilization system is gas engine cost, installation cost, and maintenance cost.

Table 5.8 Diesel Generator for electric motor cost

Monthly Operation Expense	Cost per month (Baht)
Diesel Engine Rental Cost (Main)	45,000
Diesel Engine Rental Cost (Backup)	45,000
O&M Cost	10,000
Diesel Fuel (120 liters/day, 30 Baht/liter)	108,000
Total	208,000

Table 5.9 Gas engine for directly driving beam pump instead of diesel engine.

Monthly Operation Expense	Cost per month (Baht)
Gas Engine (Main)	0
Diesel Engine Rental Cost (Backup)	45,000
Diesel Fuel (8 liters/day, 30 Baht/liter)	7,200
O&M cost for gas generator	10,000
Total	62,200

Difference between Table 5.8 and Table 5.9 total cost is monthly operating cost saving, which is 145,800 Baht/month. Major investment of this option is purchasing and installation cost for gas engine as follows:

Table 5.10 Gas Engine Project Investment Cost

Investment	Cost (Baht)
Gas Engine Purchasing cost	450,000
Piping and valves system cost	30,000
Installation cost	30,000
Total	510,000

For cash flow analysis and NPV, Table 5.11 and 5.12 show cash flow of diesel and gas engine respectively. From the table 5.12, the gas engine option shows a lot better economic result. The NPV of gas engine is dramatically more than the diesel engine.

Table 5.11 diesel engine cash flow of well A-01

Year No.	Diesel Engine Rental Cost(Baht)	Diesel Fuel Cost (Baht)	Diesel Engine Expense (Baht)	Gas Engine Operation & Maintenance Expense (Baht)	Cash Flow (Baht)	Diesel Engine 10 % Discount Cash Flow (Baht)
0	1,080,000	1,296,000	2,376,000	120,000	-2,496,000	-2,496,000
1	360,000	432,000	792,000	40,000	-832,000	-756,364
Total				160,000	-3,328,000	-3,252,364

Table 5.12 On-site gas engine cash flow of well A-01

Year No.	Gas Daily Production @ the end of the year (SCFD)	Gas Engine Cost(Baht)	Piping and Installation Cost	Electric Generation Capital Expense (Baht)	Gas Engine Operation & Maintenance Expense (Baht)	Gas Engine Straight Line Depreciation (Baht)	Cash Flow (Baht)	Gas Engine 10 % Discount Cash Flow (Baht)
0	5,000	450,000	60,000	510,000	746,400	255,000	-1,001,400	-1,001,400
1	5,000			0	248,800	255,000	6,200	5,636
Total					995,200	510,000	-995,200	-995,764

Year 1 cash flow was calculated for 4 months according to production forecast result.

Payback period can be calculated by divided investment cost by monthly operation cost saving which is

Payback Period = Gas Engine Cost/Cost Saving per month
= 510,000/145,800
= 4 months

NPV shows 3 times higher than using diesel engine. The result clearly shows that gas engine obviously pass both technical and economic feasibility study and should be installed at recommended wells.

To select the candidate wells, there are some points that have to be considered as follows:

1. Associated gas production should be at least 5,000 scfd.
2. Forecast production life for both oil and gas should be longer than payback period (4 months)
3. The well should have at least 6 months of stable oil and gas production profile.

The recommended wells that gas engine should be installed are shown in Table 5.13

Table 5.13 Recommended wells for installing gas engine

Well	Flow Mechanism	Average Associated Gas (scfd)	Forecast Oil Production life (months)
A-01	Beam Pump	10,000	14
A-03	Beam Pump	8,100	6
A-09	Beam Pump	6,400	40
A-11	Beam Pump	13,000	6
B-06	Beam Pump	13,000	40

Recommended wells have substantial gas for gas engine and also show a good profile of oil production. These wells pass both technical and economic scan. By the way, there is still a risk for implementing the option because oil and gas production based on high uncertainty of variable production rate and sharp decline. This might result in temporary shut in for weeks to several months. However, the 4 months payback period is short. The risk of shut in these wells before this period is acceptable compare to the benefit.

5.6.3 On-site Gas Generator

There are some well sites that have large amount of associated gas production than 15,000 scfd. These sites used 120 KVA diesel generators, that consumed diesel of 260 liters/day, to generate electricity for the whole site. Meanwhile, large amount of associated gas from these wells have been flared since the production started.

In this case, diesel generator can be effectively substituted by gas generator, which would result in considerably high cost saving. However, technical and economic feasibility have to be performed to confirm this.

The gas generator was chosen to substitute 120 KVA diesel generator. The specification is shown in Table 5.14

This gas generator needs minimum 15,000 scfd of associated gas for stable running.

With this gas generator specification, these criteria have been proposed for preliminary check and filter out some wells.

1. Well should produce gas continuously at least 15,000 scfd
2. Using beam pump (ESP is relatively overload for gas generator)

Some high production wells with ESP, has very high associated gas rate, but they should not be proposed because ESP needs a consistency power source and consumes a lot of power. The vary associated gas flowrate from unconventional reservoir is not reliable enough to use as a main source of energy. If gas production sharply declined, ESP would have stopped working. This could result in pausing production for several days.

Table 5.14 VR380 Gas Generator Specifications

VR380 SPECIFICATIONS

Displacement	380.8 cubic inches (6.24liters)
Bore	4.134" (105mm)
Stroke	4.724" (120mm)
Speed Range	1,000-1,800 rpm, 1,000-2,000 intermittent duty
Maximum Continuous Horsepower	80.4 Bhp @ 1,800 rpm
Normal Oil Pressure	70 psi @ 1,800 rpm (average) 45 psi @ 1,800 rpm (minimum)
Oil Temperature	180°F (82.25°C) Full Load STD Day
Normal Coolant Temperature	180°F (82.25°C) Full Load STD Day
Dry Weight	1,851lbs. (840kg.)
Number of Cylinders	6
Compression Ratio	9:1
Firing Order	1,5,3,6,2,4
Number of Main Bearings	7
Engine Length	63 1/2" (161.3cm)
Engine Width	28 1/4" (71.75cm)
Engine Height	48" (121.9cm)
Crankcase capacity (Including Filter)	20qts. (19liters)
Valve Clearance, Cold (Intake)	0.2mm (0.008") see page 37 for more details
Valve Clearance Cold (Exhaust)	0.3mm (0.012") see page 37 for more details
Flywheel Housing	SAE 3

Table 5.15 shows the diesel generator cost, which is mainly the rental charge and the fuel cost. This cost will be greatly reduce if substitute one set of diesel generator with gas generator. However, another set has to be kept as a backup.

Table 5.15 Monthly Cost of diesel generator

Monthly Expense	Cost per month (Baht)
125 KVA Diesel Generator Rental Cost (Main)	50,000
125 KVA Diesel Generator Rental Cost (Backup)	50,000
O&M Cost	10,000
Diesel Fuel (260 liters/day, 30 Baht/liter)	234,000
Total	344,000

Table 5.16 shows the cost analysis if diesel generator is substituted by gas generator. Gas generator need to be stop working around 1 hour per day for daily checkup. During this period, backup diesel generator has to be run. This consumes approximately 8 liters of diesel.

Table 5.16 Monthly cost of gas generator

Monthly Expense	Cost per month (Baht)
Gas Generator (Main)	0
125 KVA Diesel Generator Rental Cost (Backup)	45,000
Diesel Fuel (8 liters/day, 30 Baht/liter)	7,200
O&M Cost	20,000
Total	72,200

Difference between Table 5.15 and Table 5.16 total cost is monthly operating cost saving, which is 271,800 Baht/month. Major investment of this option is purchasing and installation cost for gas engine as shown In Table 5.17.

Table 5.17 Gas Gemerator Project Investment Cost

Investment	Cost (Baht)
Gas Generator Purchasing cost	900,000
Piping and valves system cost	30,000
Installation cost	30,000
Total	960,000

For cash flow analysis and NPV, Table 5.18 and 5.19 shows cash flow of diesel and gas generator respectively. From the table 5.19, the gas generator option shows better economic result. The NPV of gas engine is dramatically more than the diesel engine.

Table 5.18 Diesel generator cash flow of well A-04

Year No.	Diesel Generator Rental Cost(Baht)	Diesel Fuel Cost (Baht)	Diesel Generator Expense (Baht)	Diesel Generator Operation & Maintenance Expense (Baht)	Cash Flow (Baht)	Diesel Generator 10 % Discount Cash Flow (Baht)
0	1,200,000	2,808,000	4,008,000	120,000	-4,128,000	-4,128,000
1	1,200,000	2,808,000	4,008,000	120,000	-4,128,000	-3,752,727
2	500,000	1,170,000	1,670,000	50,000	-1,720,000	-1,421,488
Total				290,000	-9,976,000	-9,302,215

Table 5.19 Gas generator cash flow of well A-04

Year No.	Gas Daily Production @ the end of the year (SCFD)	Gas generator Cost(Baht)	Piping and Installation Cost	Electric Generation Capital Expense (Baht)	Gas Generator Operation & Maintenance Expense (Baht)	Gas Generator Straight Line Depreciation (Baht)	Cash Flow (Baht)	Gas Generator 10 % Discount Cash Flow (Baht)
0	15,000	900,000	60,000	960,000	866,400	319,997	-1,506,403	-1,506,403
1	15,000			0	866,400	319,997	-546,403	-496,730
2	15,000			0	361,000	319,997	-41,003	-33,887
Total					2,093,800	959,990	-2,093,810	-2,037,020

Year 2 cash flow was calculated for 5 months according to production forecast result.

Payback period can be calculated by divided price of gas generator by cost saving per month. The cost of 1 set of gas generator is 900,000 Baht. Thus, payback time is

Payback Period = Gas Generator Cost/Cost Saving per month
= 960,000/271,800
= 4 months

From equation, payback period of gas generator is just 4 months which is very short. According to Table 5.19, gas generator NPV is a lot more than diesel generator. Gas generator is a very high prospect for gas utilization in term of both technical and economic.

To select the candidate wells, there are some points that have to be considered as follows:

1. Associated gas production should be at least 15,000 scfd.
2. Forecast production life for both oil and gas should be longer than payback period (4 months)
3. The well should have at least 6 months of stable oil and gas production profile.

Table 5.20 Candidate wells for on-site gas generator

Well	Flow Mechanism	Associated Gas (scfd)	Forecast Oil Production Life (months)
A-04	Beam Pump	27,470	15
A-05	Beam Pump	27,020	29
A-08	Beam Pump	203,690	10
A-10	Beam Pump	146,550	12
A-12	Beam Pump	20,412	13
A-13	Beam Pump	25,210	8
B-01	Beam Pump	52,160	10
B-02	Beam Pump	294,550	7
B-07	Beam Pump	38,190	18
B-08	Beam Pump	25,905	N/A
B-09	Beam Pump	45,110	35

The recommended wells have good oil production profile. They should be able to sustain production longer than 4 months. After installation, the project will utilize associated gas approximately 15,000 scfd.

5.7 Connclusion for Gas Utilization Project

There are 22 wells that passed technical and economic feasibility study screening. These wells have potential to establish a gas utilization project as per proposal. A list of recommendation for gas utilization is shown below.

According to feasibility study, gas utilization project for this marginal oilfield can be concluded as shown in Table 5.21.

Table 5.21 Gas Utilization Summary

Well	Flow Mechanism	Average Associated Gas (scfd)	Forecast Oil Production life (months)	Proposed Gas Utilization Option	Expected amount of gas utilization (scfd)
A-01	Beam Pump	10,000	14	Gas Engine	5,000
A-03	Beam Pump	8,100	6	Gas Engine	5,000
A-09	Beam Pump	6,400	40	Gas Engine	5,000
A-11	Beam Pump	13,000	6	Gas Engine	5,000
B-06	Beam Pump	13,000	40	Gas Engine	5,000
A-08	ESP	203,689	10	Heater Treater	7,000
A-10	ESP	146,551	12	Heater Treater	7,000
B-02	ESP	294,553	7	Heater Treater	7,000
A-04	Beam Pump	27,466	15	Gas Generator	15,000
A-05	Beam Pump	27,016	29	Gas Generator	15,000
A-12	Beam Pump	20,412	13	Gas Generator	15,000
B-08	Beam Pump	25,906	N/A	Gas Generator	15,000
A-13	Beam Pump	25,212	8	Gas Generator/Heater Treater	22,000
B-01	Beam Pump	52,160	10	Gas Generator/Heater Treater	22,000
B-07	Beam Pump	38,190	18	Gas Generator/Heater Treater	22,000
B-09	Beam Pump	45,107	35	Gas Generator/Heater Treater	22,000

Total associated gas production	1,300,000	scfd
Total Expected gas utilization	208,000	scfd
Percentage of gas utilization	16%	

This 16% gas utilization is amount of gas of the entire on-site gas utilization for this field. Even though, 208,000 scfd is not a large number, but the on-site utilization can greatly save electric city cost as well as reduce flare. Thus, it is the most feasible and suitable to implement at this marginal oilfield.

LPG and Diesel Reduction and Cost Saving

LPG and diesel reduction and cost saving per well is summarized as shown in Table 5.22

Table 5.22 LPG and diesel reduction and cost saving per well

Gas Utilization Option	LPG Reduction (kg/month)	Diesel Reduction (liter/month)	Cost Saving (Bath/month)
Heater treater	5,700		114,000
Gas engine		3,600	108,000
Gas generator		7,200	216,000

Total LPG and diesel reduction for entire field is shown in Table 5.23

Table 5.23 Total LPG and diesel reduction and cost saving for proposed wells

Gas Utilization Option	No. of proposed well	LPG Reduction (kg/month)	Total Diesel Reduction (liter/month)	Total Cost Saving (Bath/month)
Heater treater	9	51,300		1,026,000
Gas engine	5		18,000	540,000
Gas generator	8		64,800	1,944,000
Total	22	51,300	82,800	

Not only the option is economic feasible, it also greatly help reducing wasted energy, which can be clearly seen by amount of these calculated LPG and diesel reduction.

5.8 Clean Development Mechanisms Considerations

United Nations Framework Convention on Climate Change (UNFCCC) described Clean Development Mechanism as follows:

The CDM allows emission-reduction projects in developing countries to earn certified emission reduction (CER) credits, each equivalent to one ton of CO2. These

CERs can be traded and sold, and used by industrialized countries to a meet a part of their emission reduction targets under the Kyoto Protocol.

The mechanism stimulates sustainable development and emission reductions, while giving industrialized countries some flexibility in how they meet their emission reduction limitation targets.

The CDM is a mechanism where Annex I countries (see appendix c) with a specific obligation to reduce a set amount of greenhouse gas (GHG) emissions by 2012 under the Kyoto Protocol assist non-Annex I (see appendix c) countries to implement project activities to reduce or absorb (sequester) at least one of six GHGs (see Table 5.24). Non-Annex I countries are signatories and ratifiers to the Kyoto Protocol; however, they do not adhere to reduction targetsstipulated under the protocol. The reduced amount of GHGs becomes credits called certified emission reductions (CERs), which Annex I countries can use to help meet their emission reduction targets under the protocol (UNFCCC 1997).

Table 5.24 Greenhouse Gas List

Greenhouse gas	Global warming potential
Carbon dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous oxide (N_2O)	310
Hydrofluorocarbons (HFCs)	140–11,700
Perfluorocarbons (PFCs)	6,500–9,200
Sulfur hexafluoride (SF_6)	23,900

This section will mention about the possibility to propose this gas utilization option as a CDM project. The main consideration on CDM is an Emission Reduction.

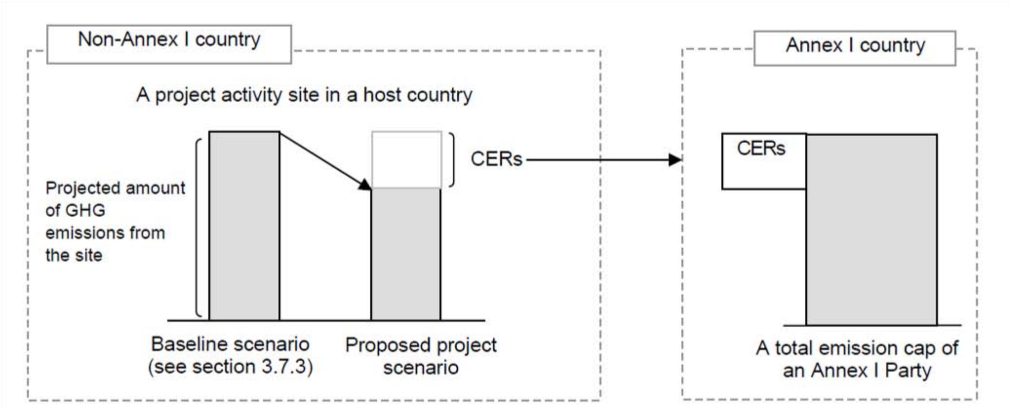

Figure 5.12 Diagram of how CDM functions
(CDM Country Guide for Thailand, Ministry of Environment, Japan, 2006)

Emission Reduction

Associated gas that consumed by gas engine, burn by heater treater and flared, still emits carbon. Therefore, emission reduction is calculated based on carbon emission reduction from reduced amount of LPG and diesel usage.

Diesel carbon dioxide emission is	2.68	kg CO_2/liter
LPG Carbon Dioxide emission is	3	kg CO_2/kg LPG

(CDM Executive Board, UNFCCC)

If every proposed well has been established a gas utilization equipment, the emission reduction would be:

615,600 kg/year of LPG reduction could reduce CO2 emission of 1,847 ton/year
993,600 liter/year of diesel reduction could reduce CO2 emission of 2,663 ton/year

CDM opportunity evaluation

According to the basic CDM consideration, CDM project must not be worth to operate without subsidize from CDM. The proposed on-site gas utilization options are high benefit projects. They clearly do not need any subsidies as a motivation to establish gas utilization project. Therefore, this gas utilization options are not qualify for CDM.

CHAPTER VI
CONCLUSIONS AND RECOMMENDATIONS

In this study, gas utilization options studied to list the options including their limitations. The main limitation is the nature of unconventional reservoir which has short production life. The feasible options have been reviewed by using both technical and economic feasibility study. Thereafter, the candidate wells were proposed the most feasible project for flared gas utilization. The result of the study clearly shown that on-site gas engine and gas generator is the most feasible project. Besides, off-site gas generator is not economically feasible due to short production life.

From chapter V study result, the characteristic of gas utilization project for this unique marginal oilfield can be performed only a project with small investment and short payback period because the production life is short and vary. Therefore, the suitable project is on-site gas generation which can be reached payback period in 4 months. On-site gas engine can be quickly implemented whenever the field operator is ready. According to the study, the sooner of starting the project, the better result for both economic and technical aspect. Moreover, this project can reduce large amount of fuel usage.

Several remarks on studying flared gas utilization for unconventional oilfield in Thailand presented as follows:

1. The gas utilization options can be changed, if there is a new technology presented.
2. Economic feasibility study is the important factor for investor to make a decision. It shows suitable option for this field. If there is a dramatically change in some factors, such as amount of associated gas largely increase, the studied result could be changed.
3. The reservoir simulation for this unconventional oilfield has not been studied because it requires profound knowledge of complex reservoir simulation, and detailed reservoir characteristics, which could be researched on the next level of study.

4. Most of the wells have almost constant or increasing tendency of associated gas production. This is a sign of solution gas drive reservoir.
5. The sharp decline of oil or gas production could unexpected happens. This is a major risk of producing from volcanic reservoir.
6. Off-site gas utilization is not economically feasible because gas supply can‘t sustain until NPV becomes positive.
7. On-site gas utilization options are both technical and economic feasible. There are 22 proposed wells for establishing a gas utilization options.
8. Carbon emission reduction is calculated from amount of reduced LPG and diesel usage. The associated gas emission is still the same.
9. The proposed on-site gas utilization options are not suitable for CDM because they are high benefit projects. They clearly do not need any subsidies as a motivation to establish gas utilization project.

The following points are recommended for future study:

1. The reserve in this study is determined by decline curve analysis only. If there is more data about reservoir properties in the future, reserve estimation should be calculated by other method such as volumetric method to cross check with DCA result.
2. With current condition, proposing the project as a CDM is not feasible. However, if there is a rise in associated gas production, CDM should be performed a feasibility study.

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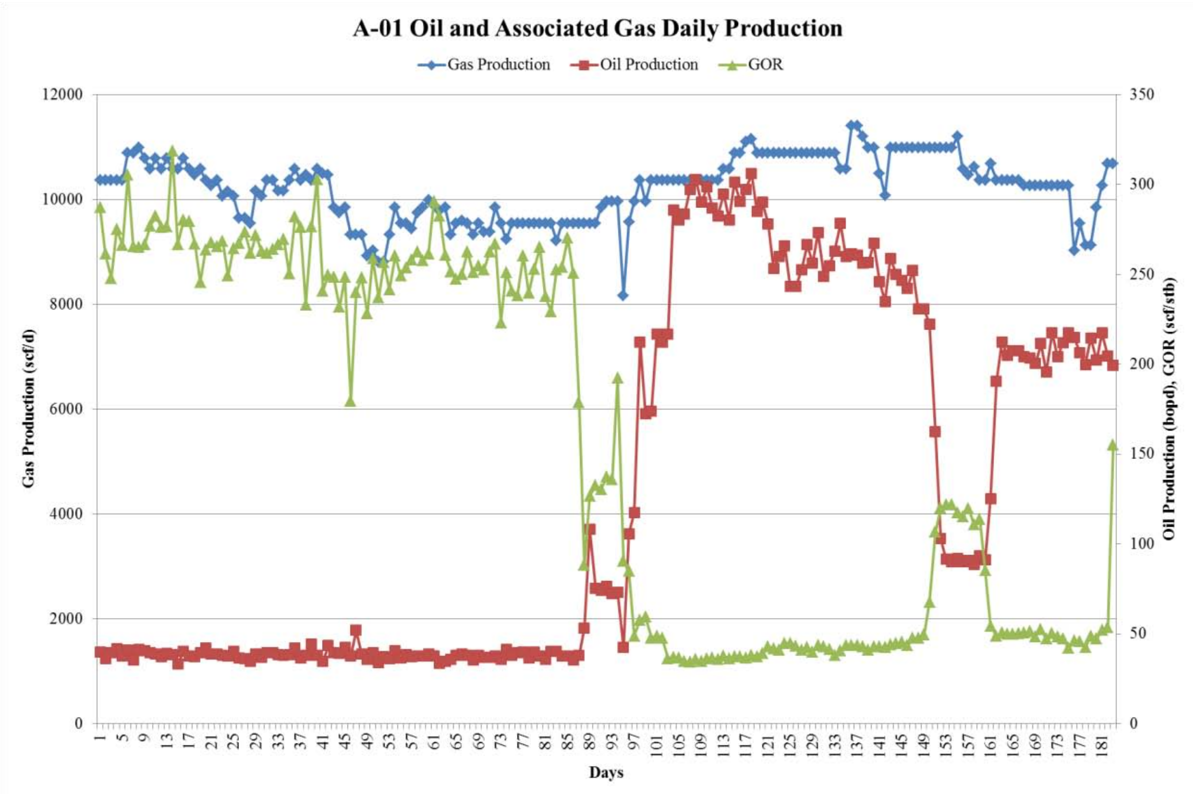
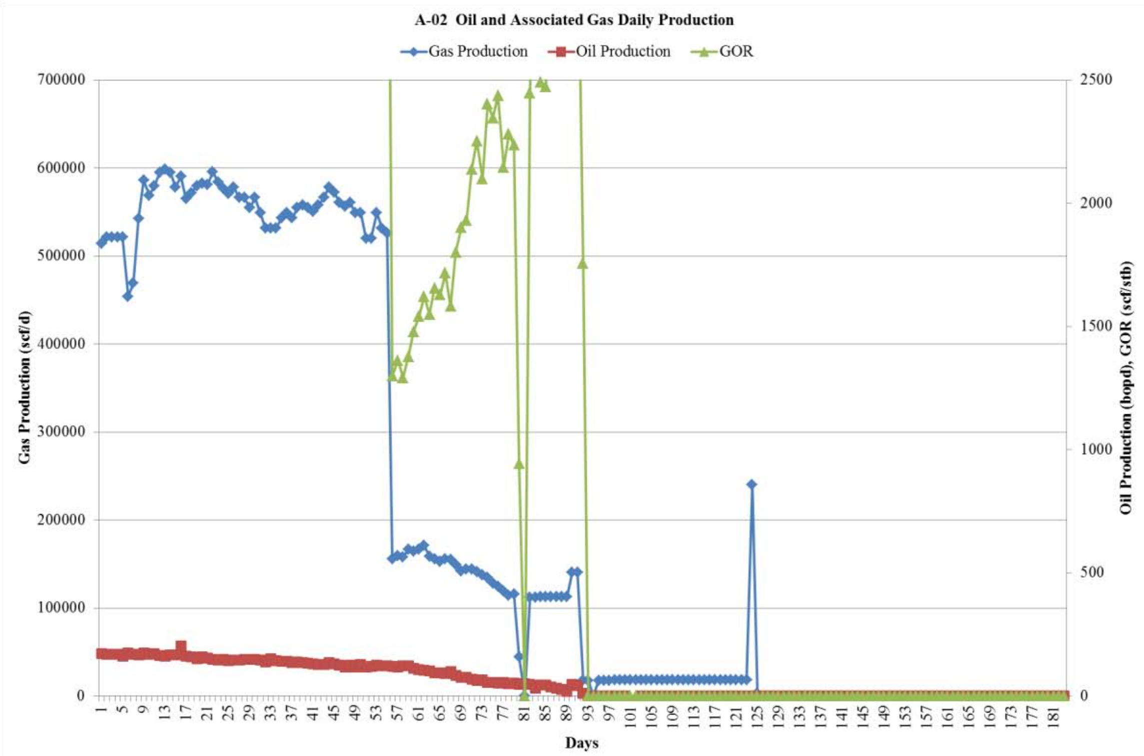
APPENDIX

APPENDIX

1. Production Profile

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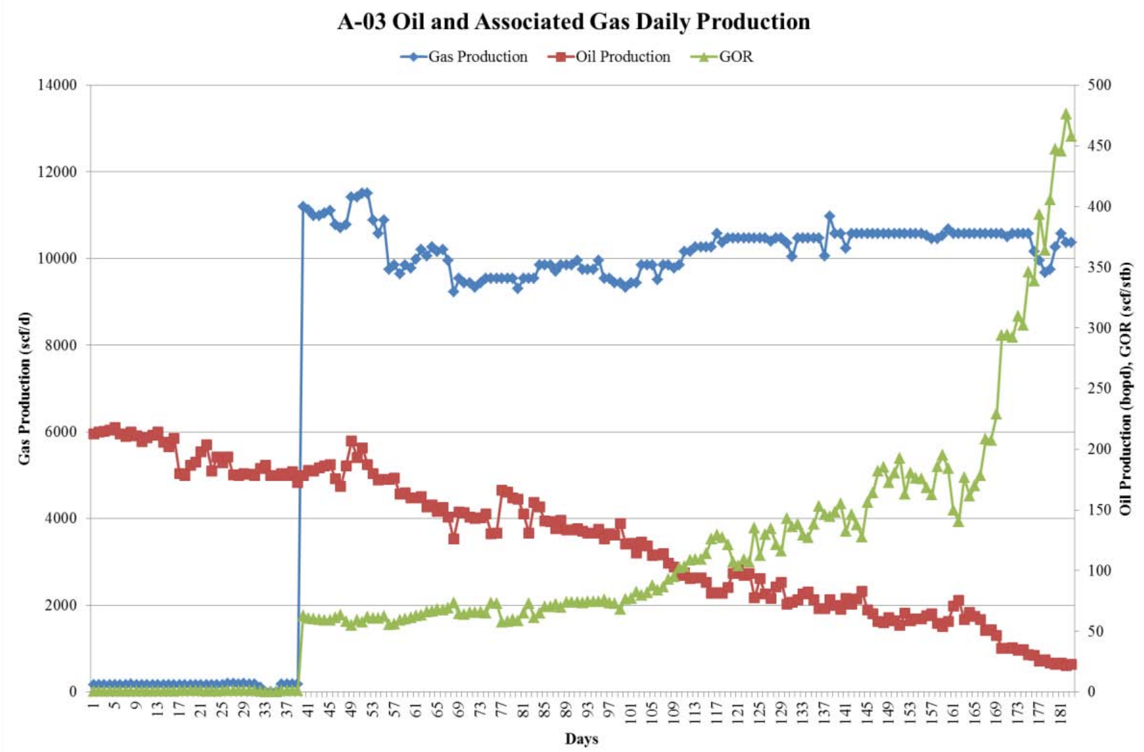
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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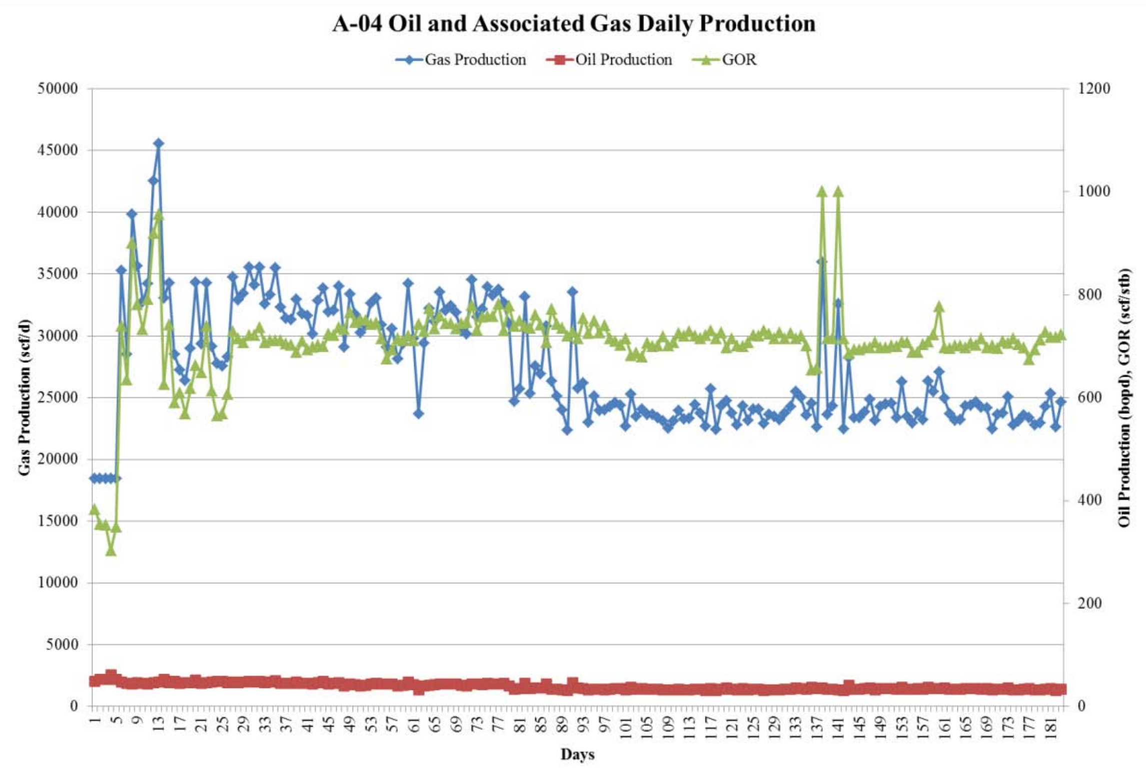
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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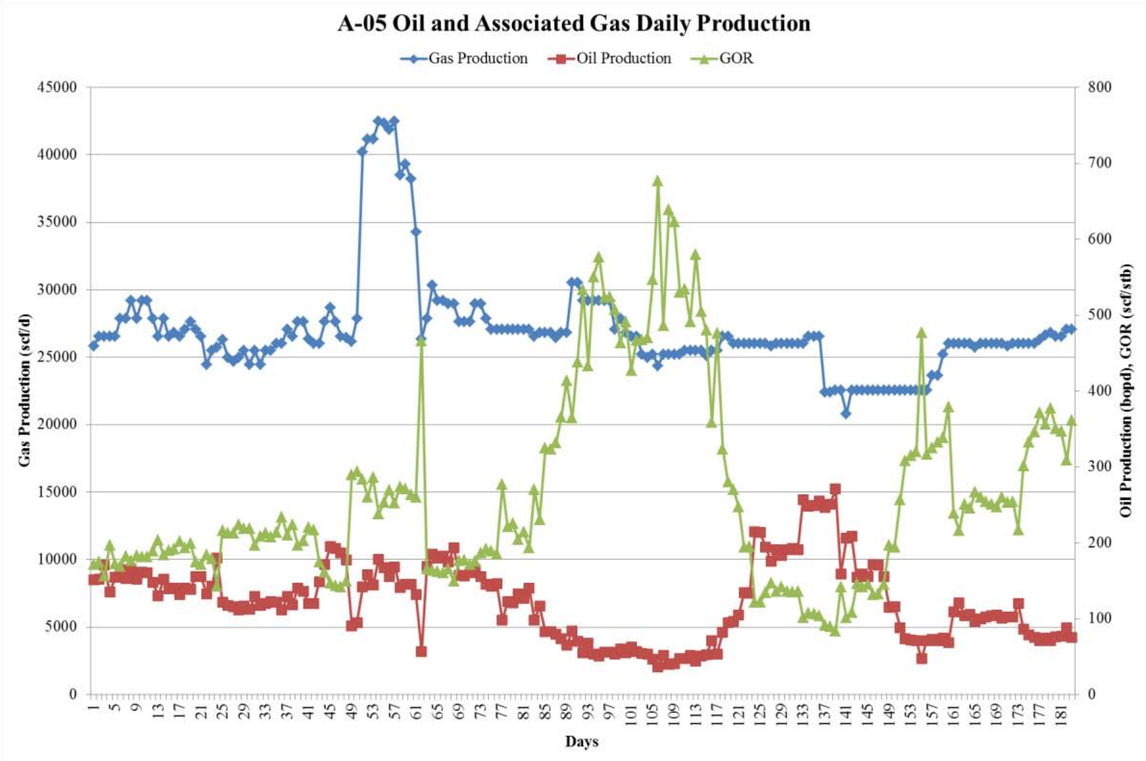
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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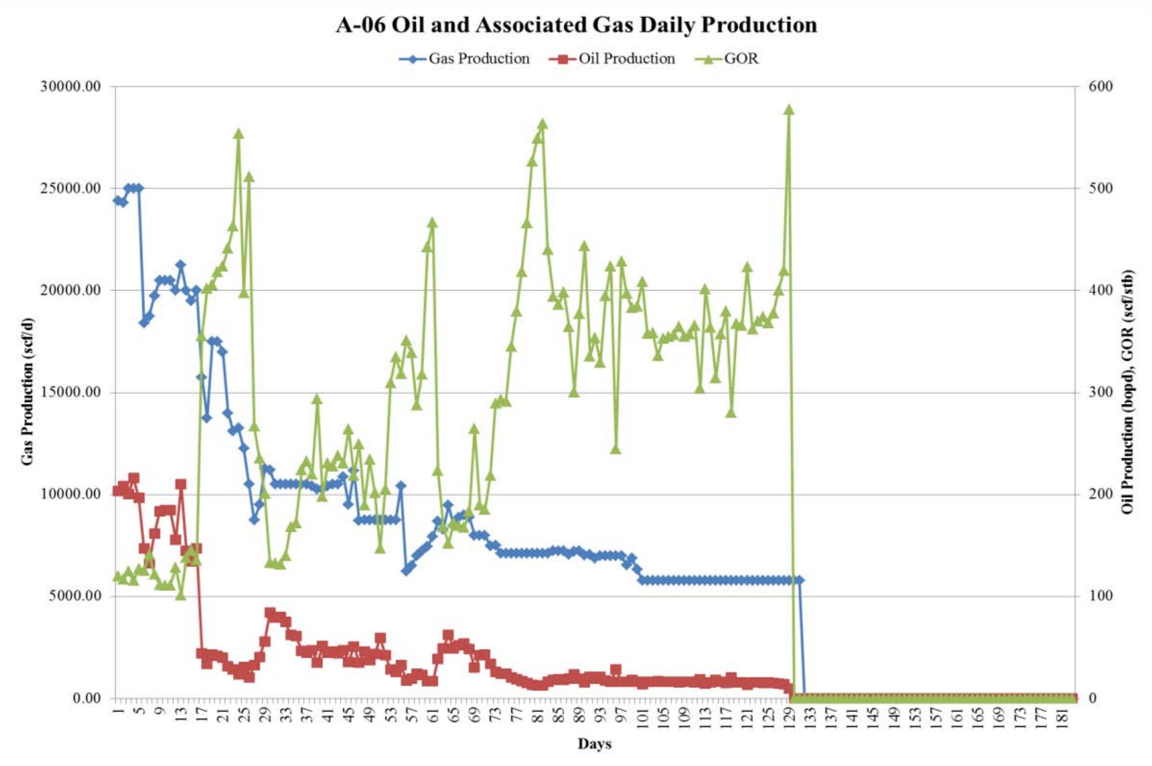
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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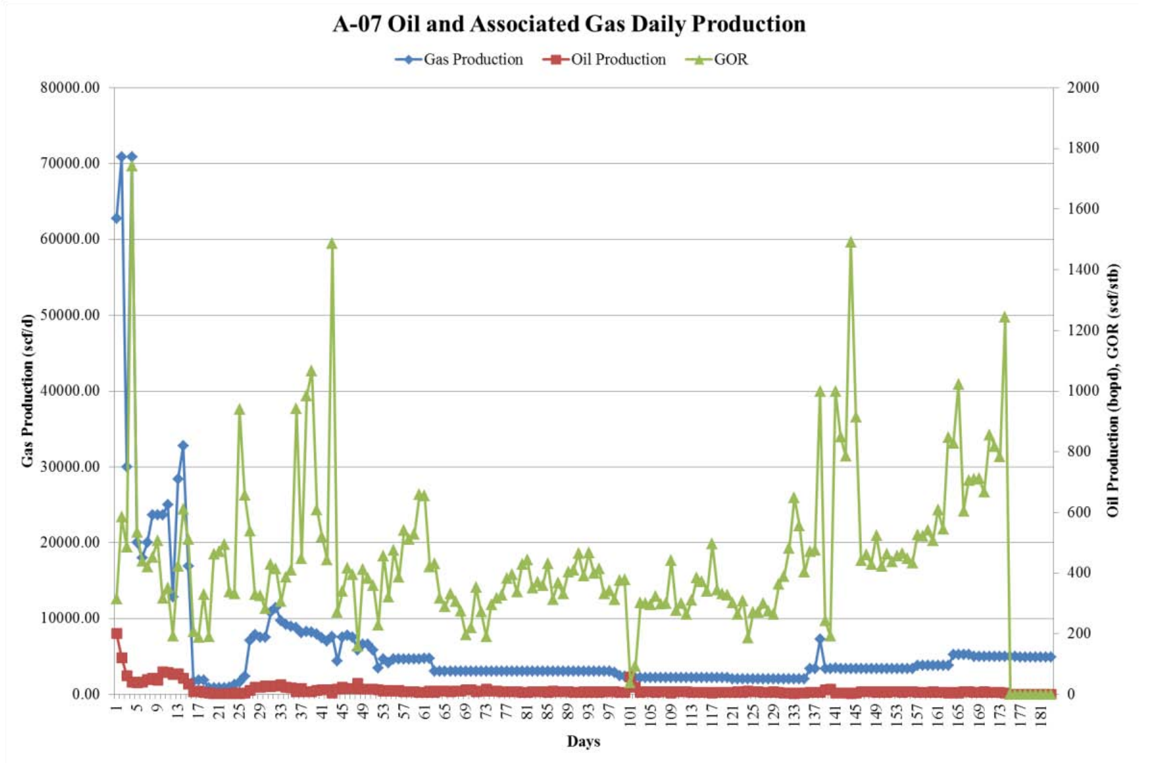
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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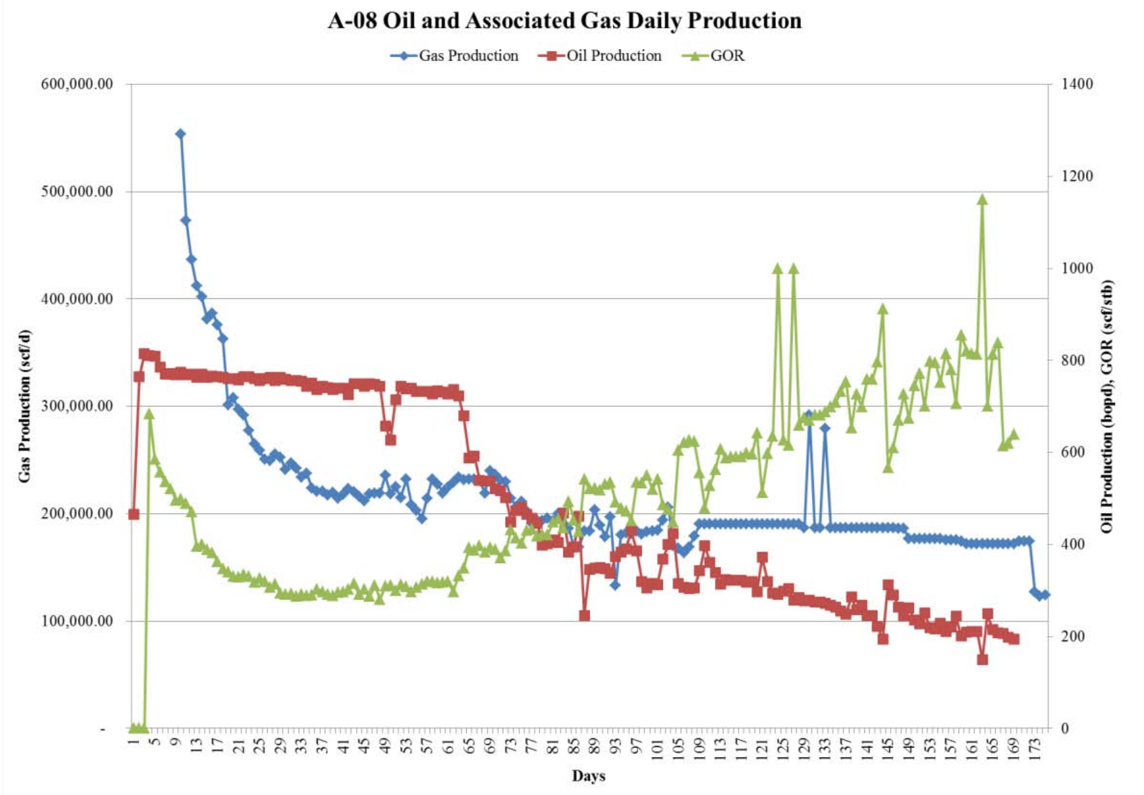
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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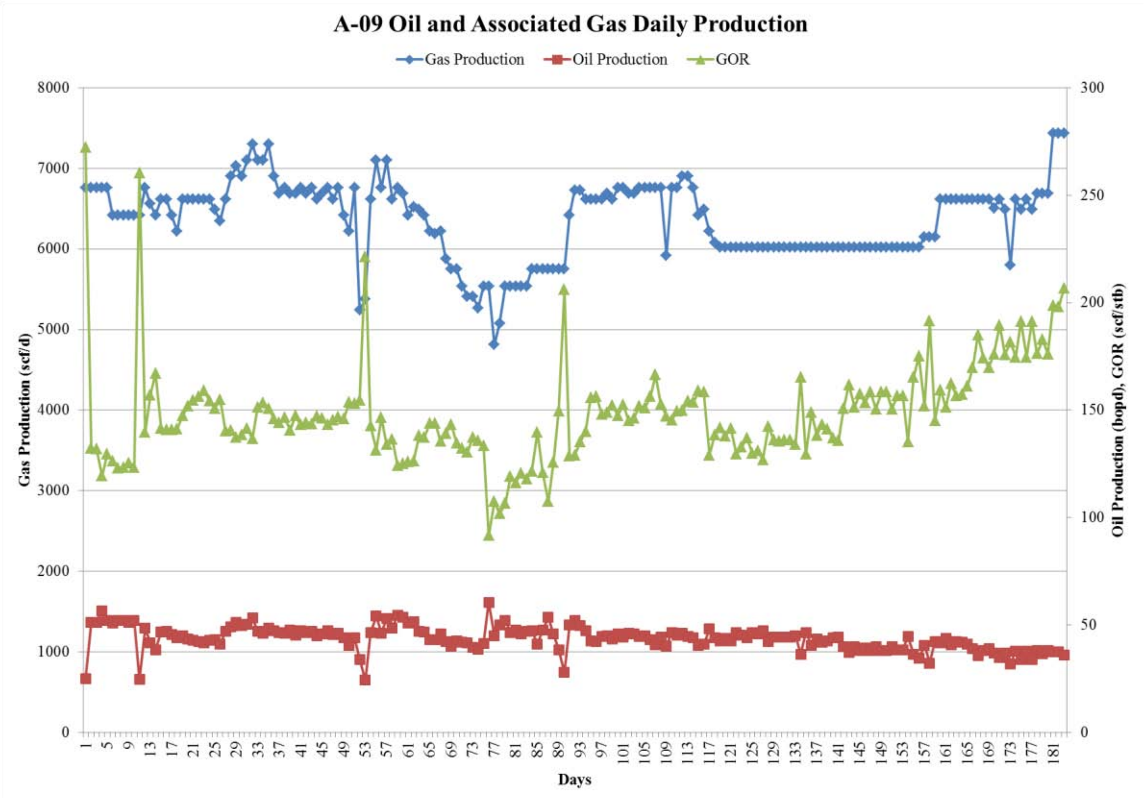
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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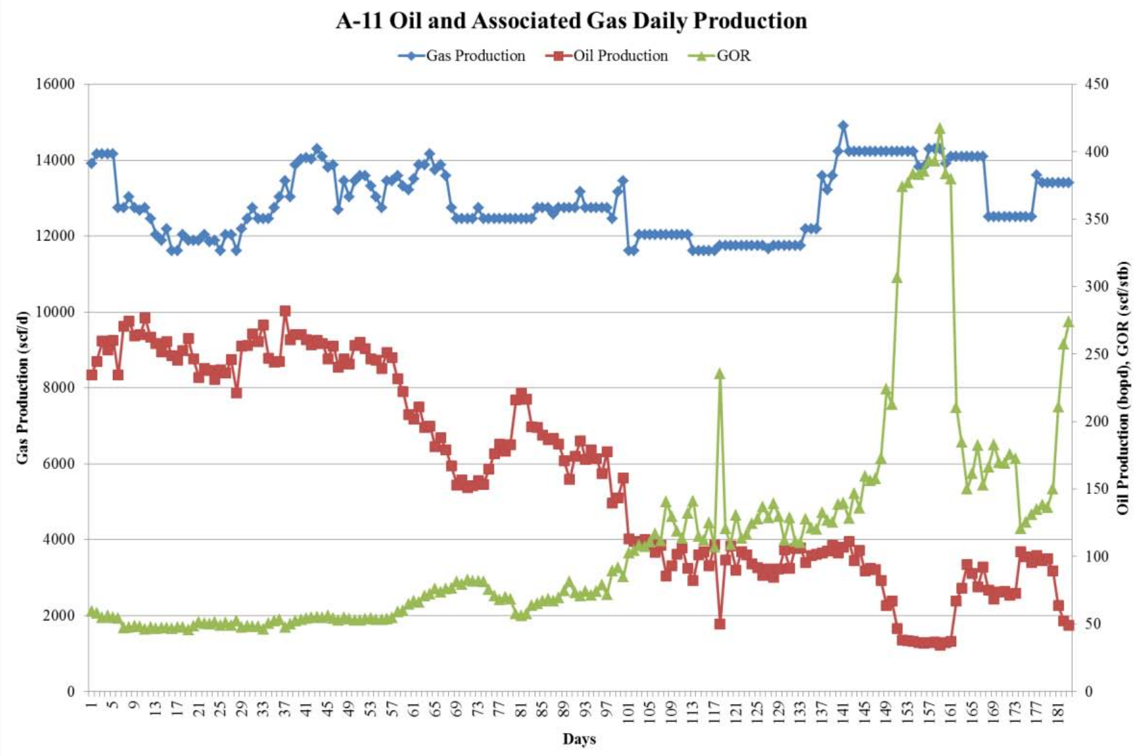
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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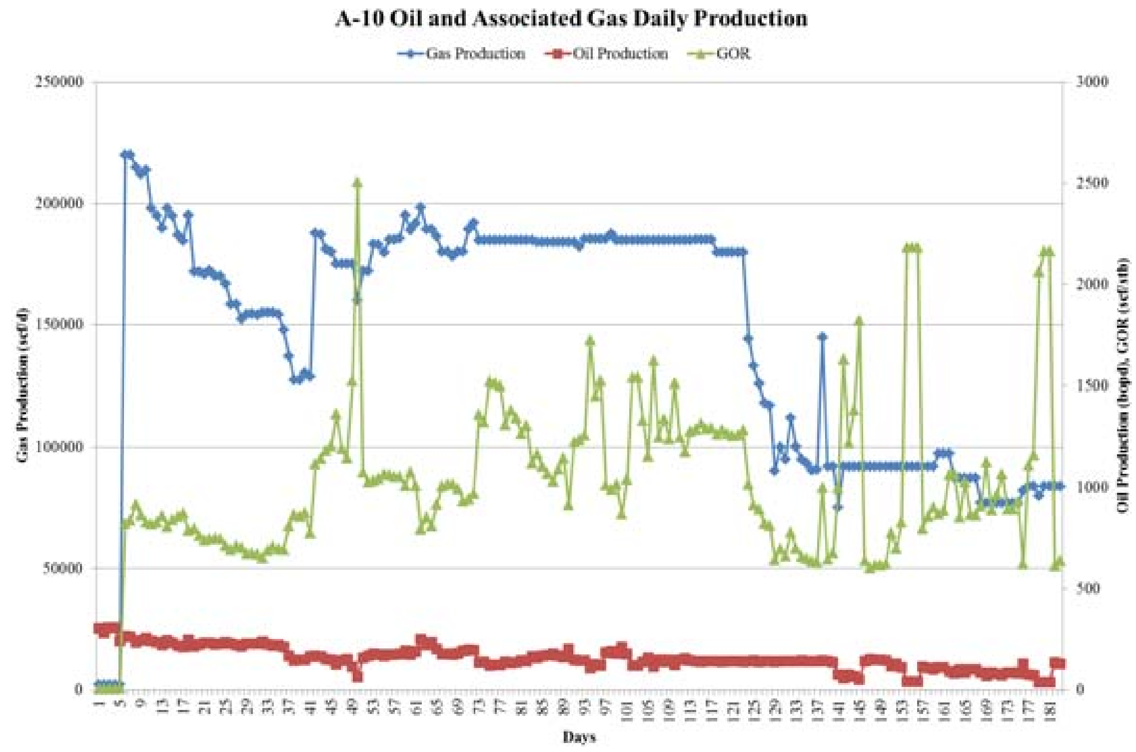
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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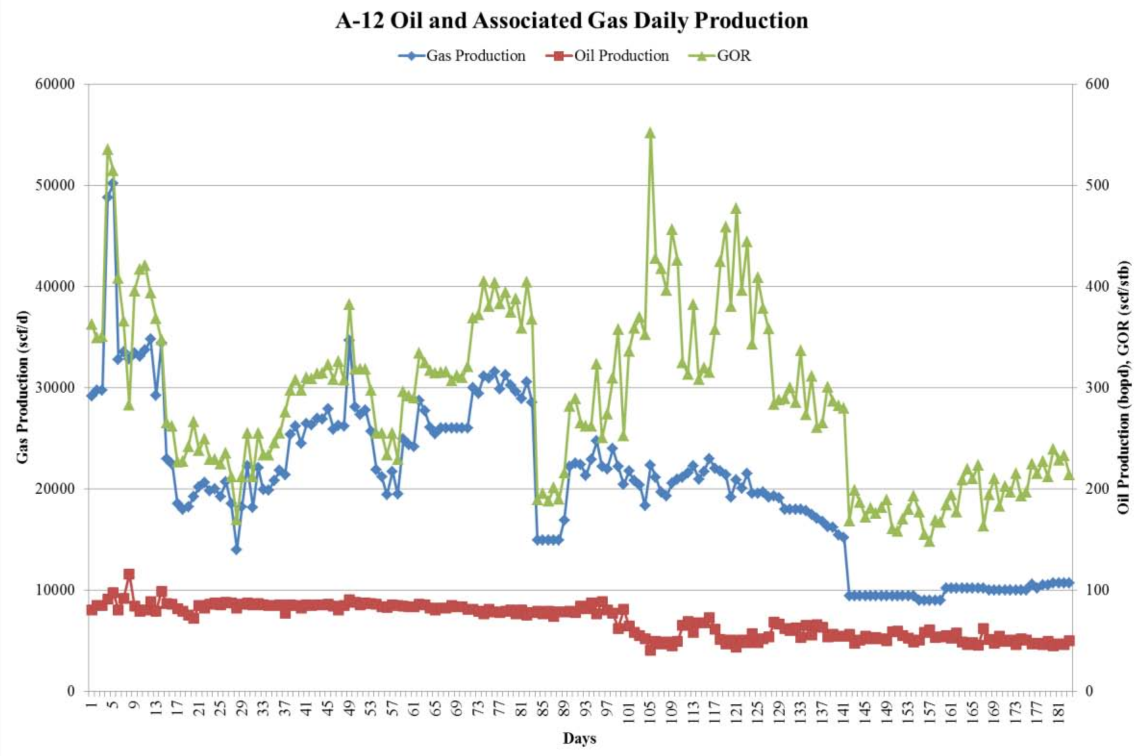
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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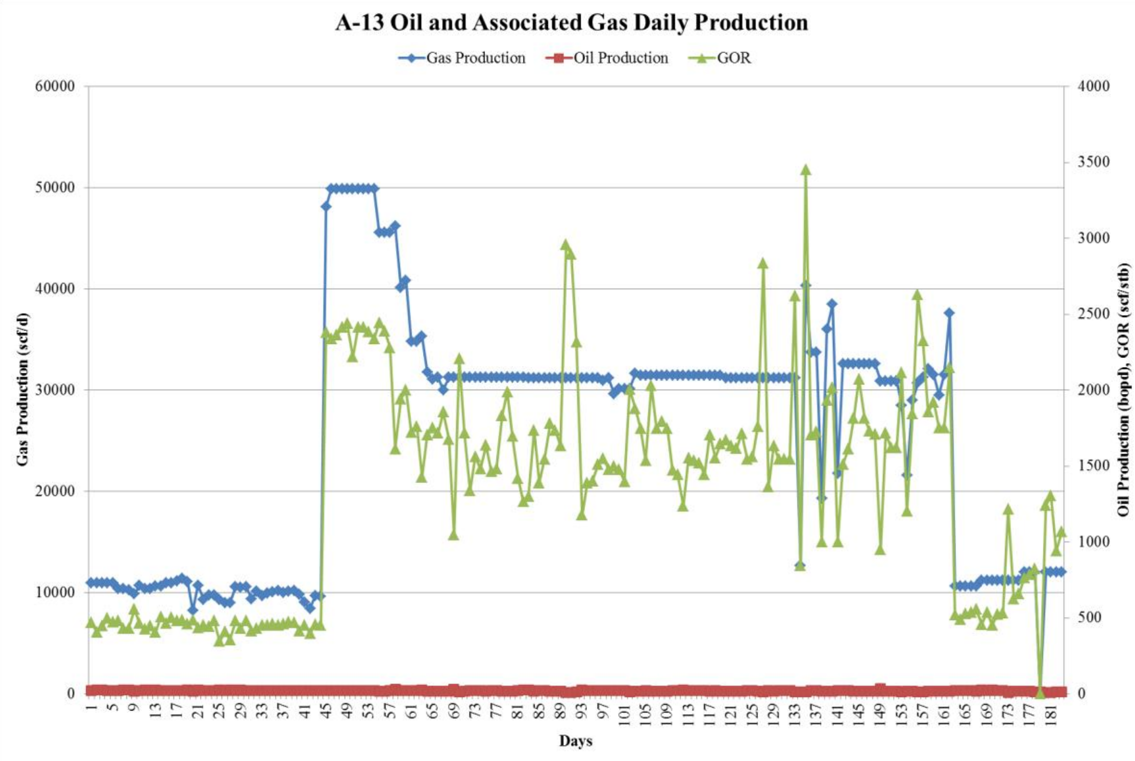
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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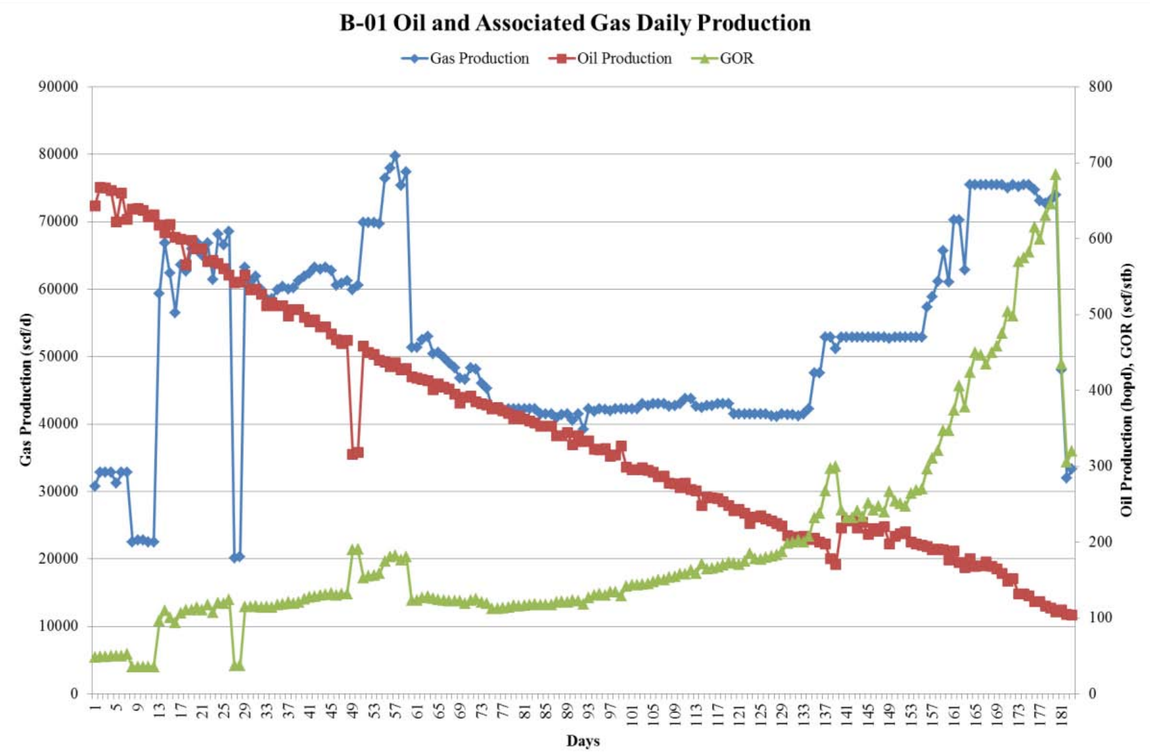
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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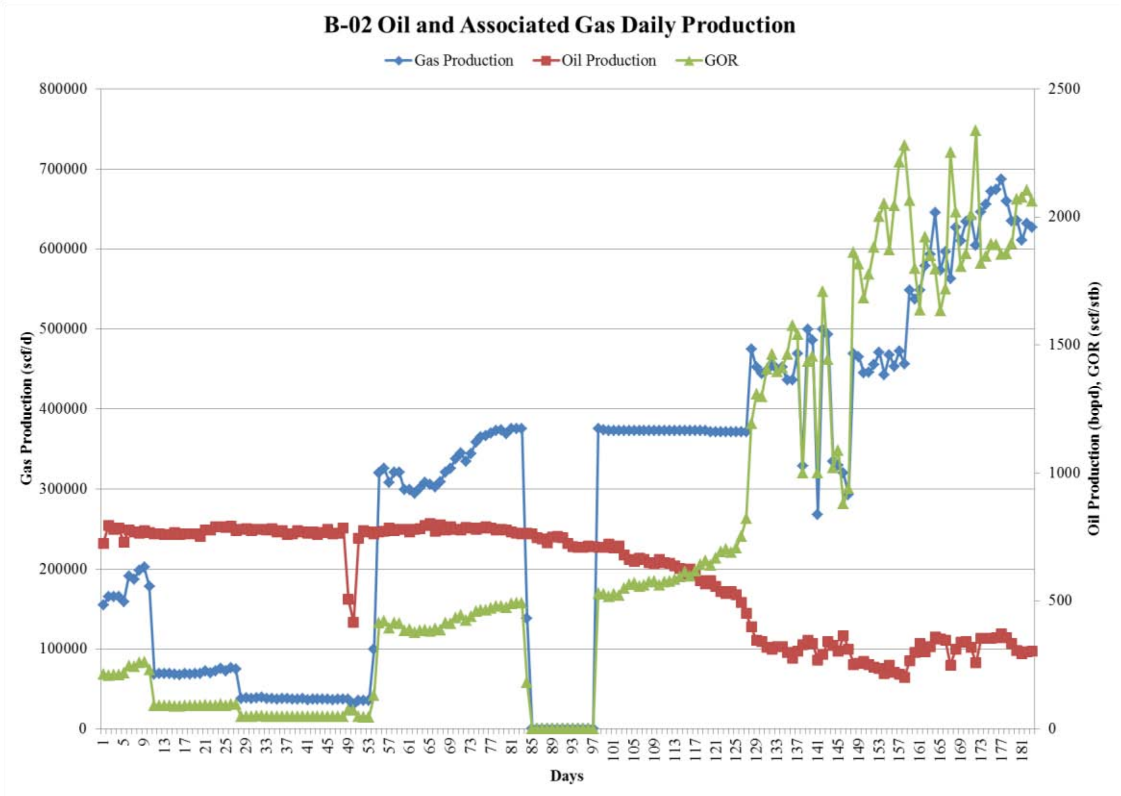
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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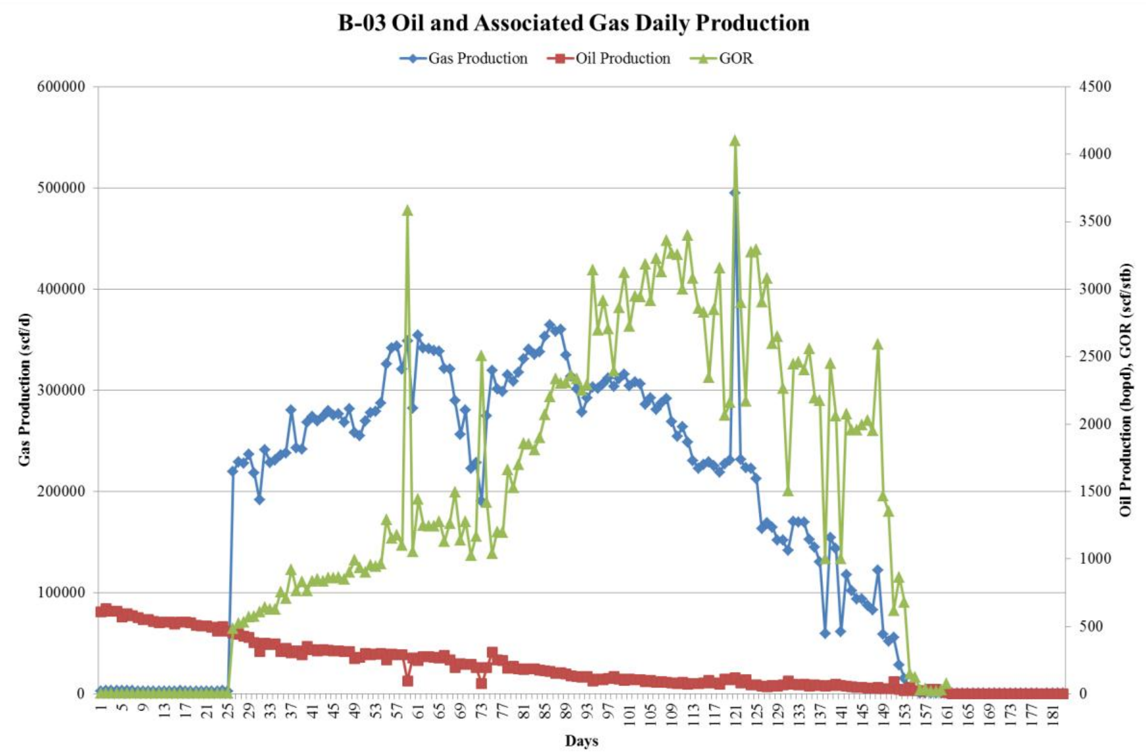
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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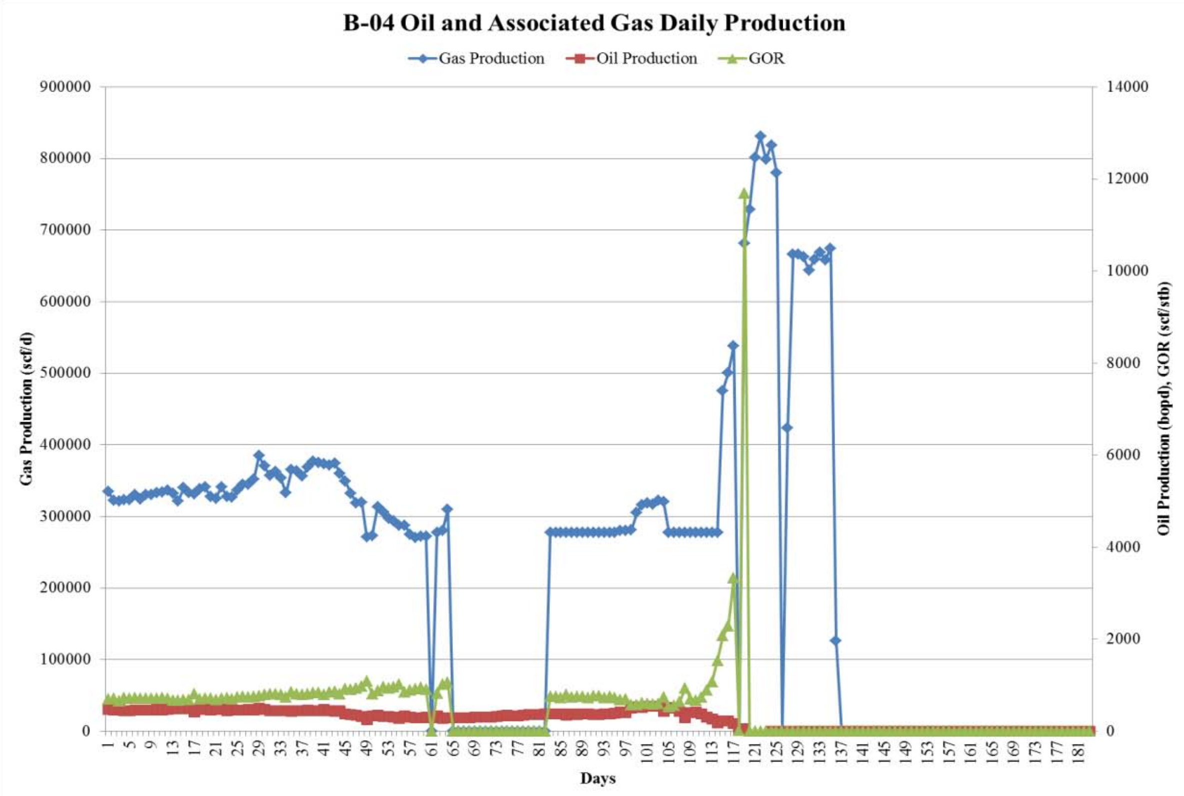
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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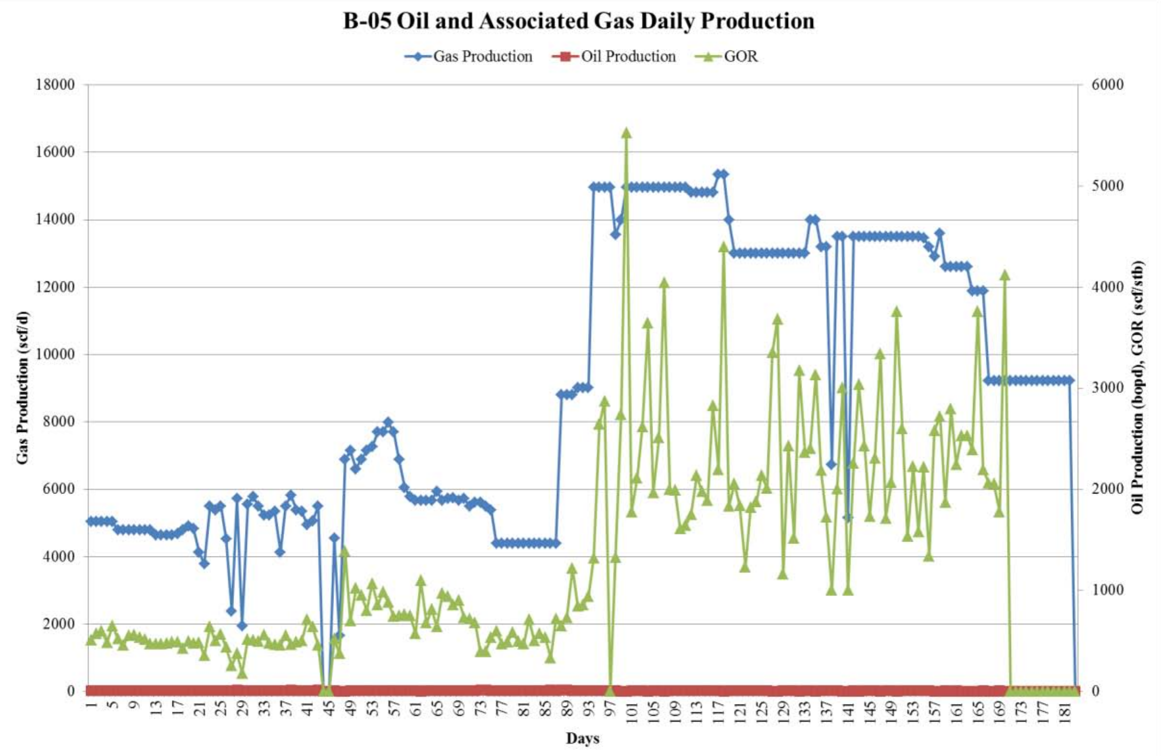
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days



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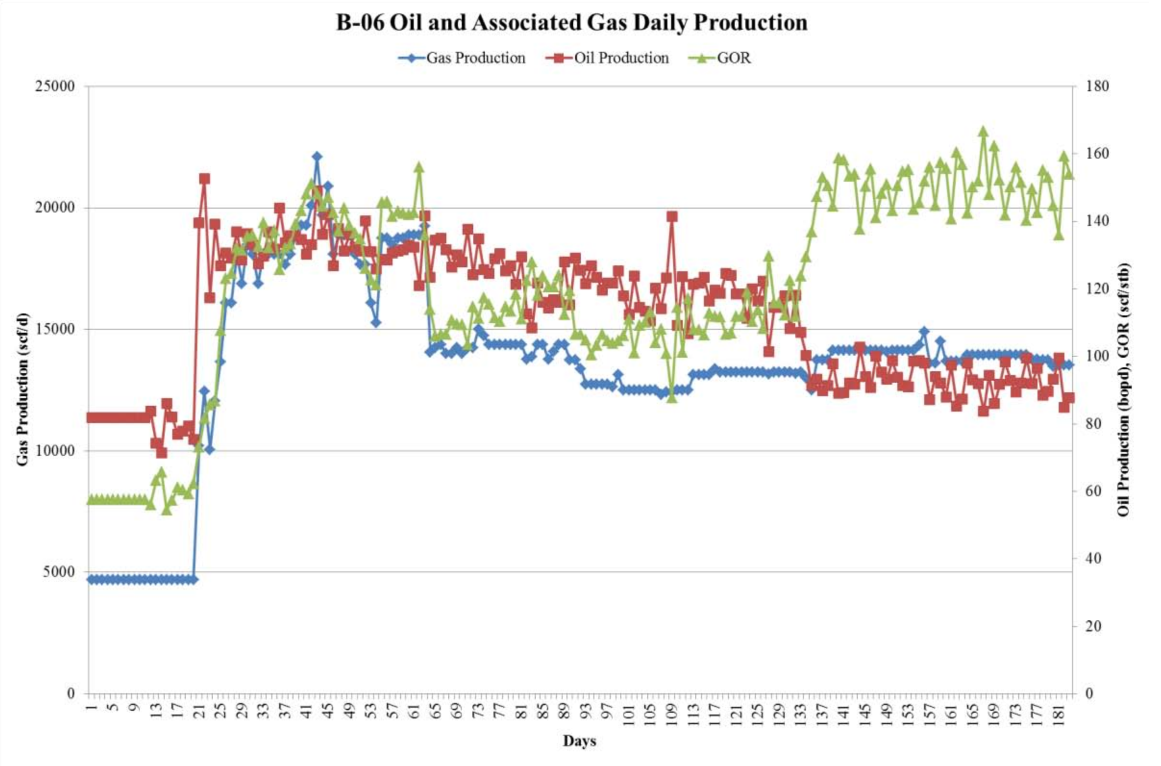
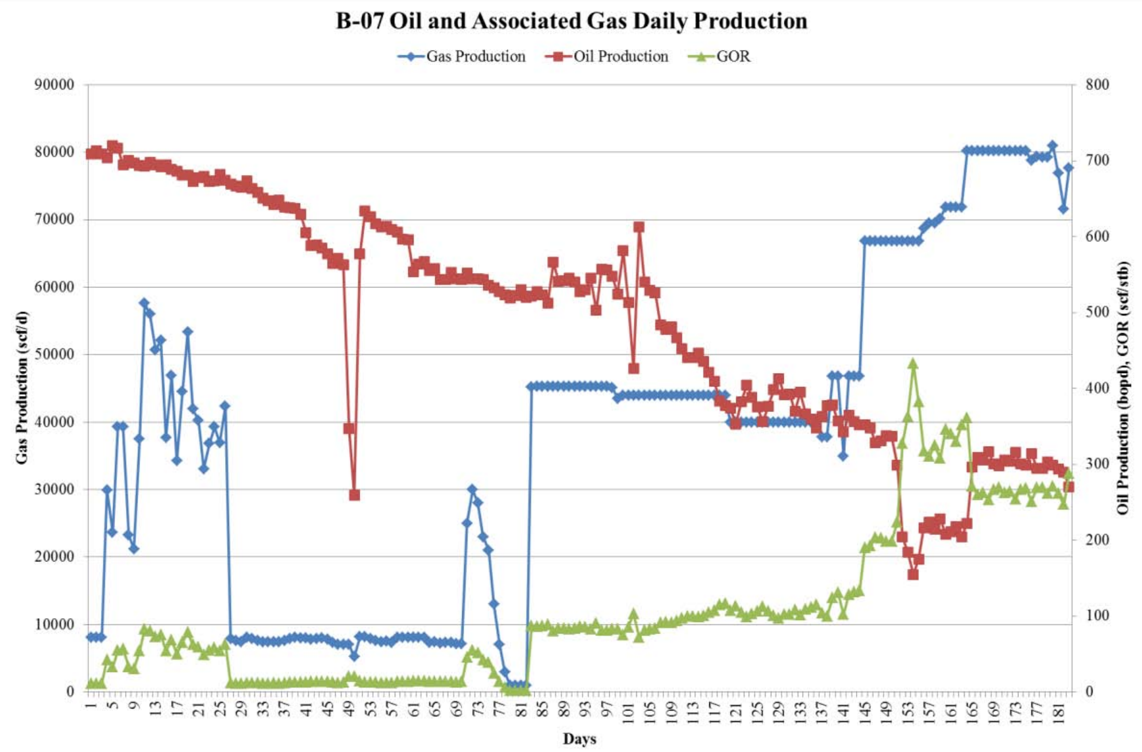
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days



B-06 Oil and Associated Gas Daily Production
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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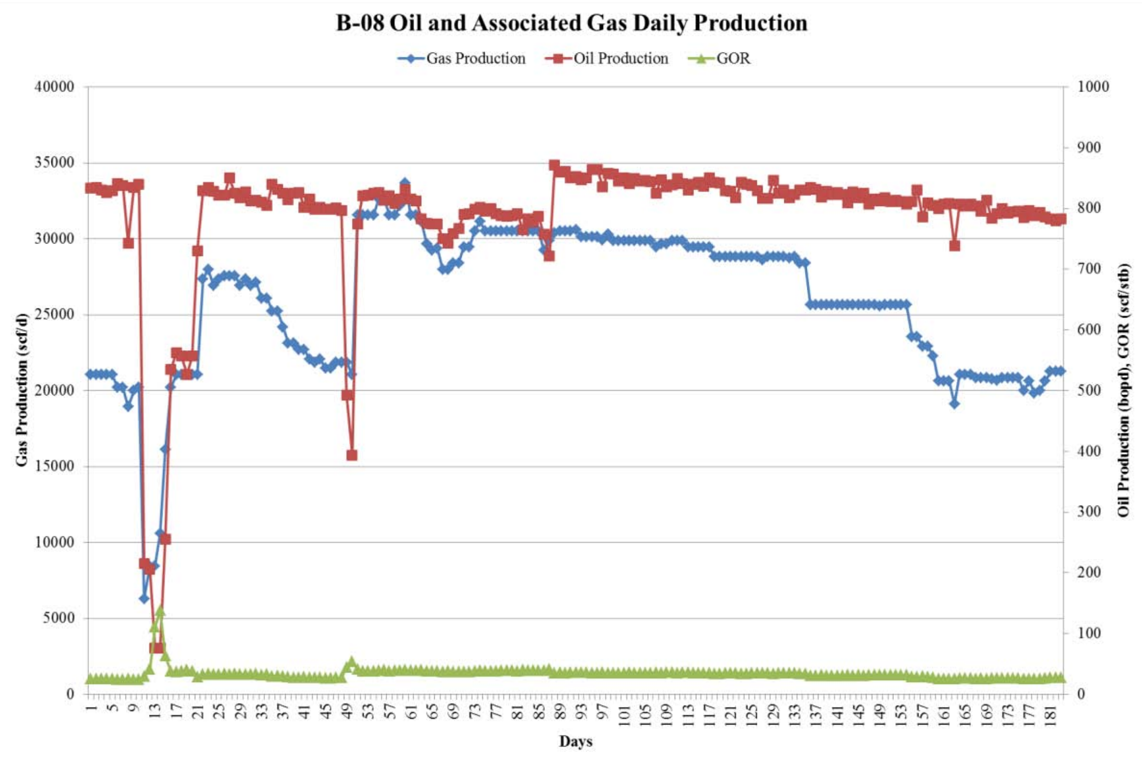
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days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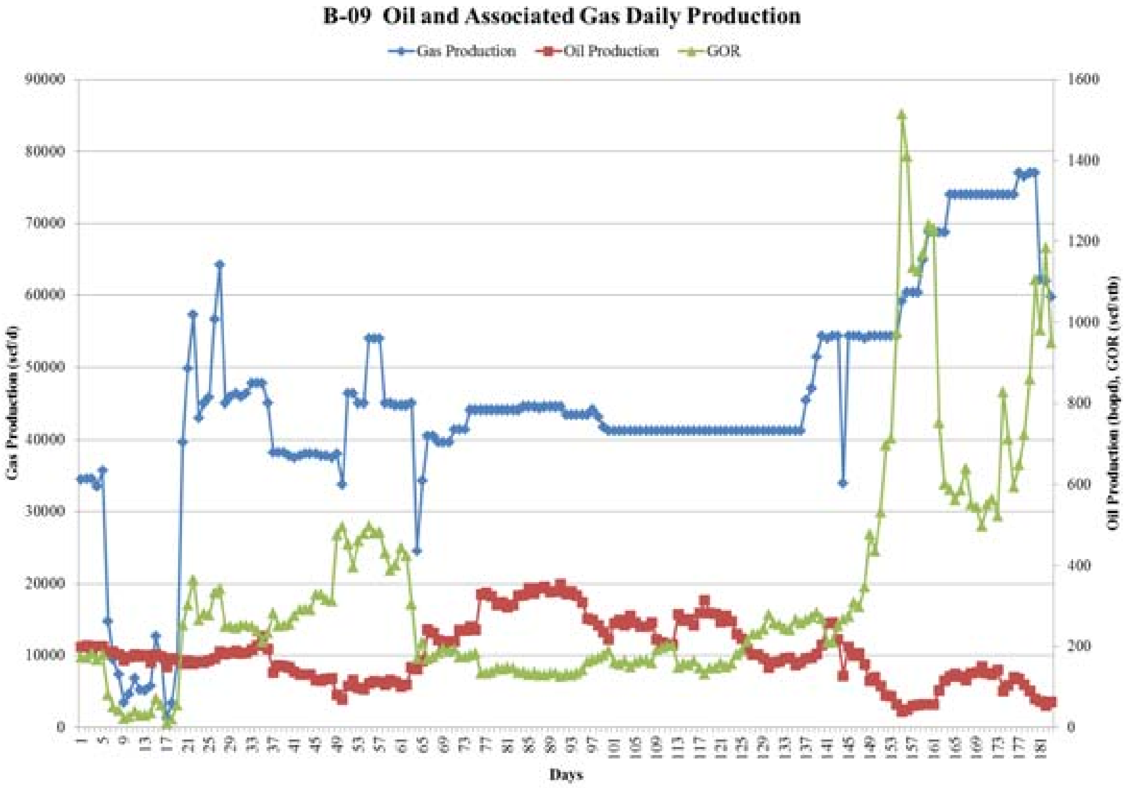
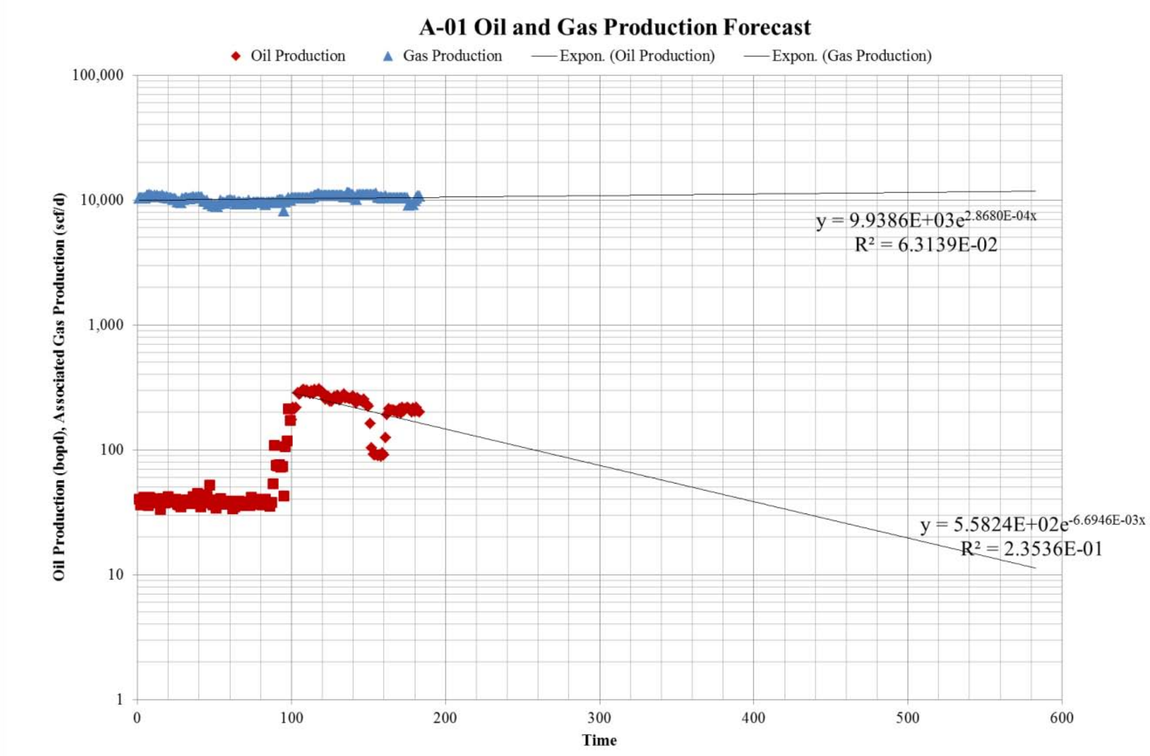
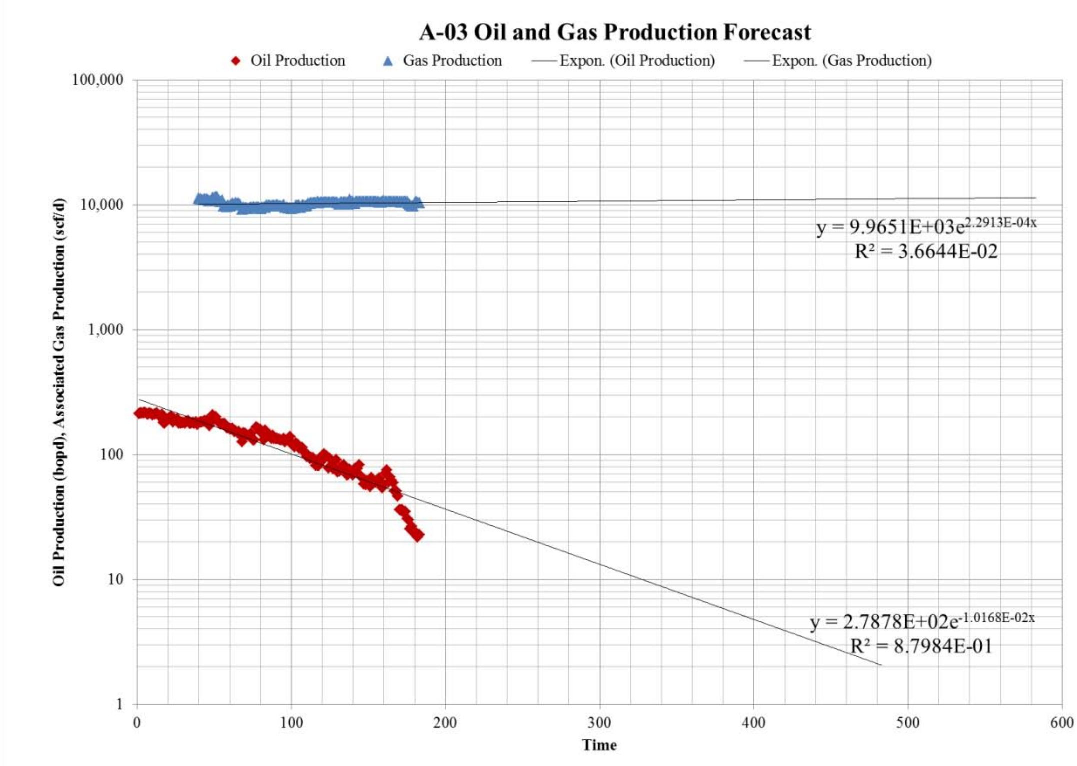
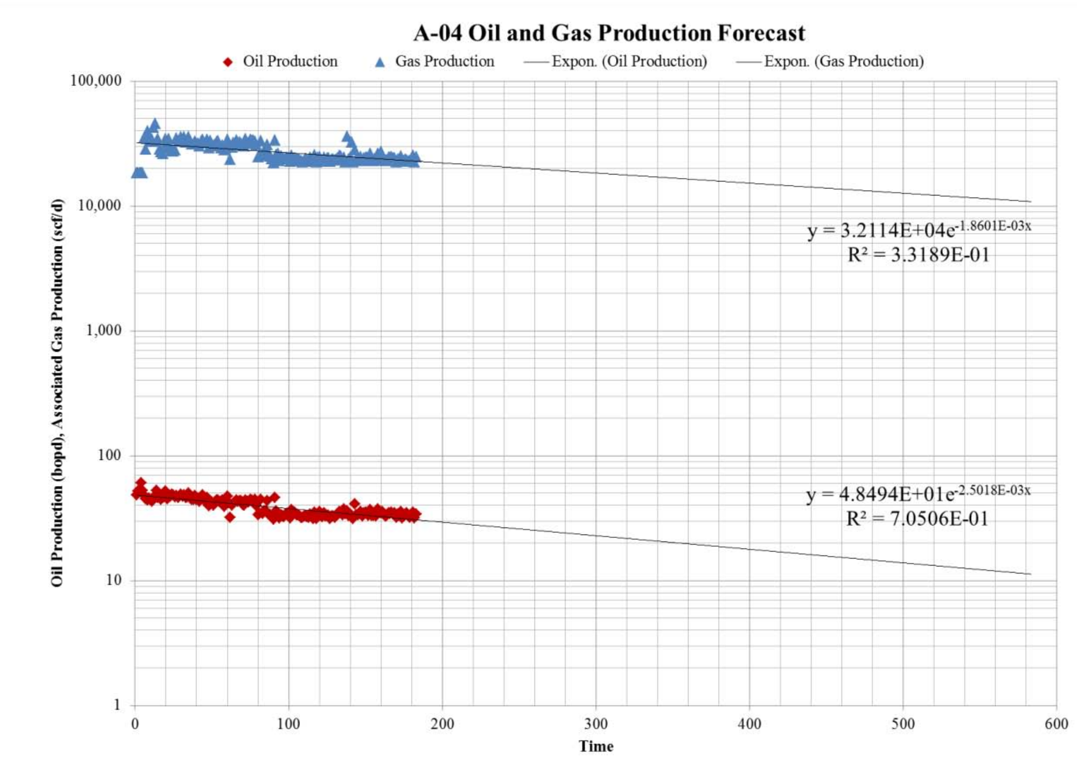
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days

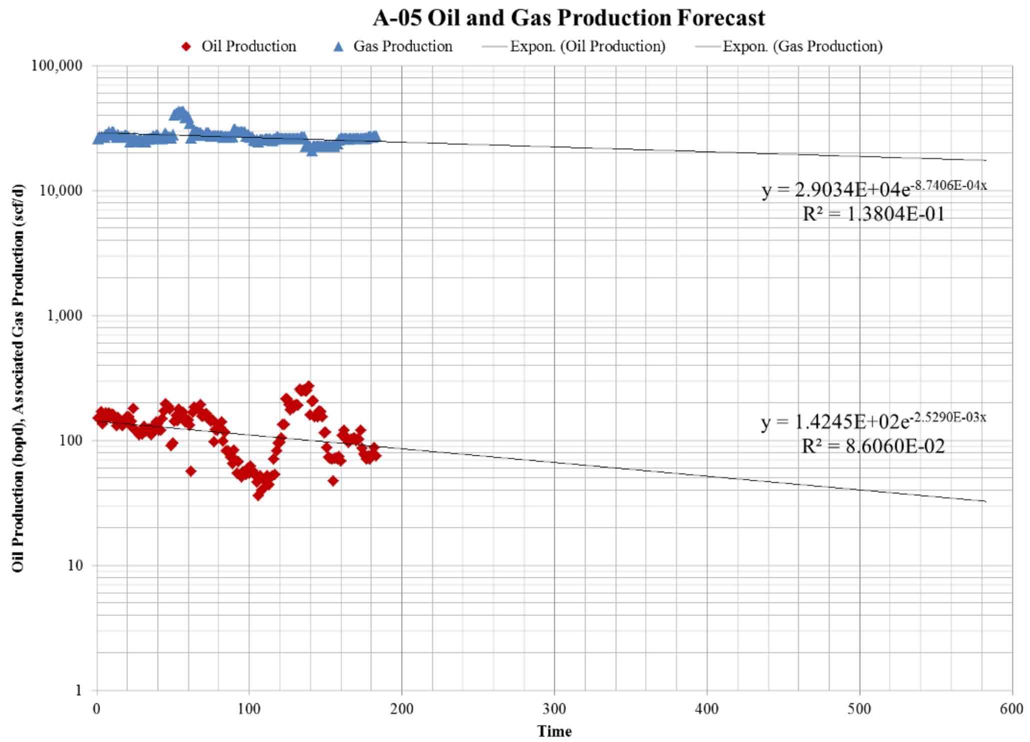

B-09 Oil and Associated Gas Daily Production
Gas Production
Oil Production
GOR
Gas Production (scf/d)
Oil Production (bopd), GOR (scf/stb)
Days

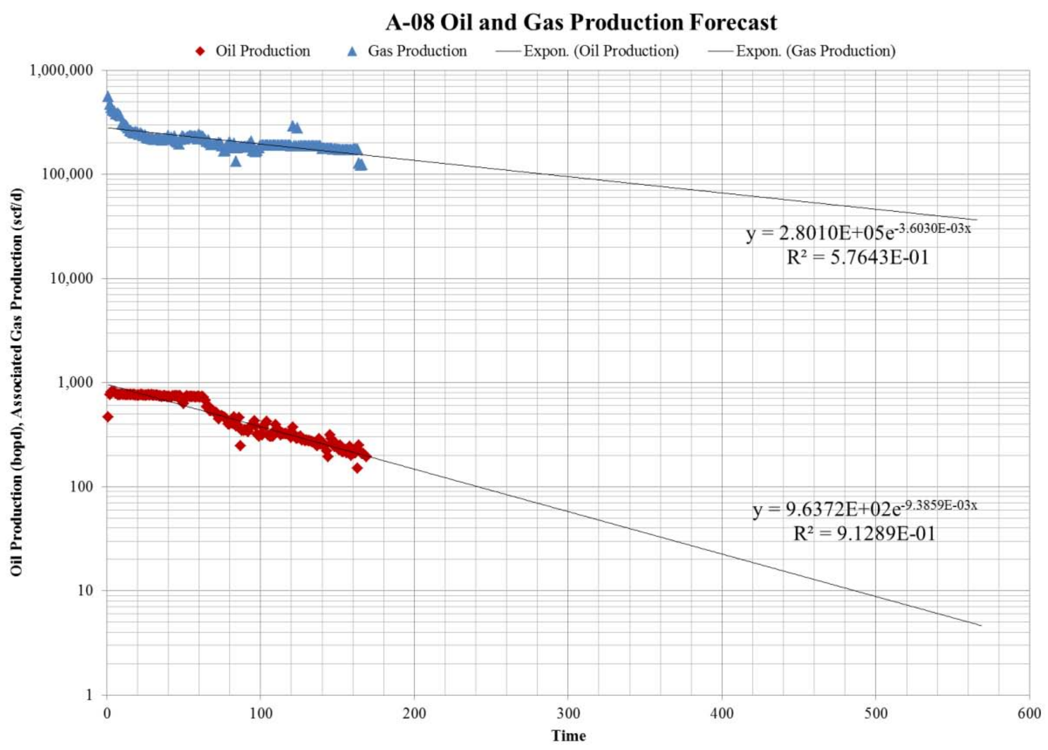
2. DCA plot (only producing well)

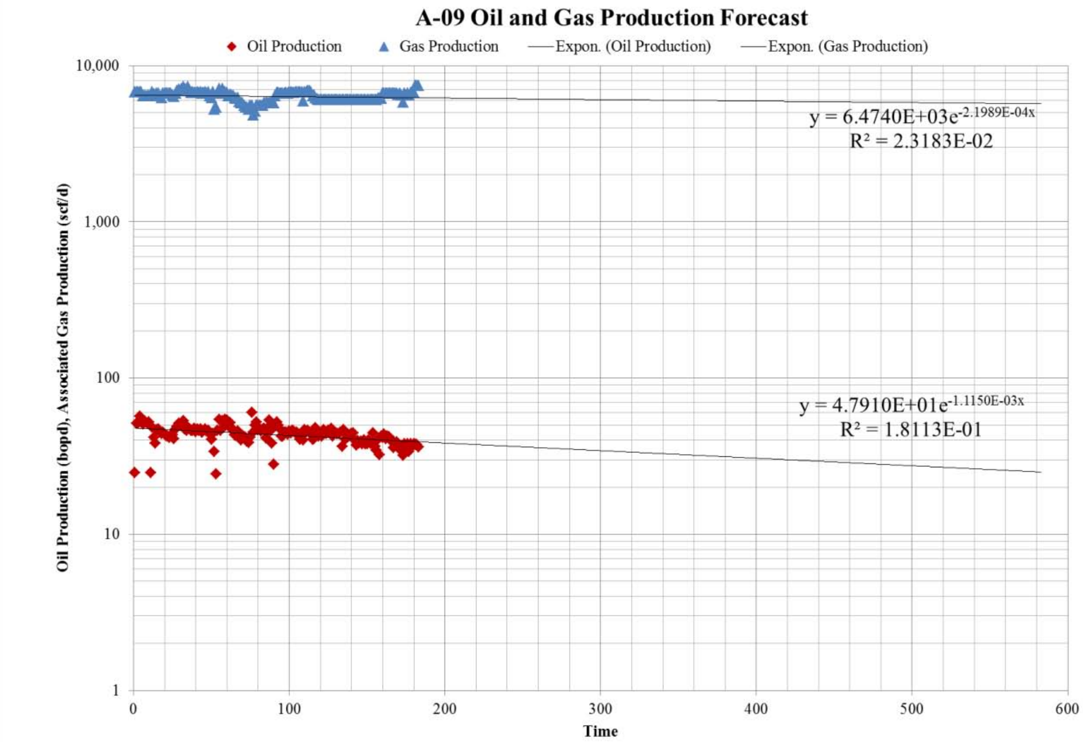


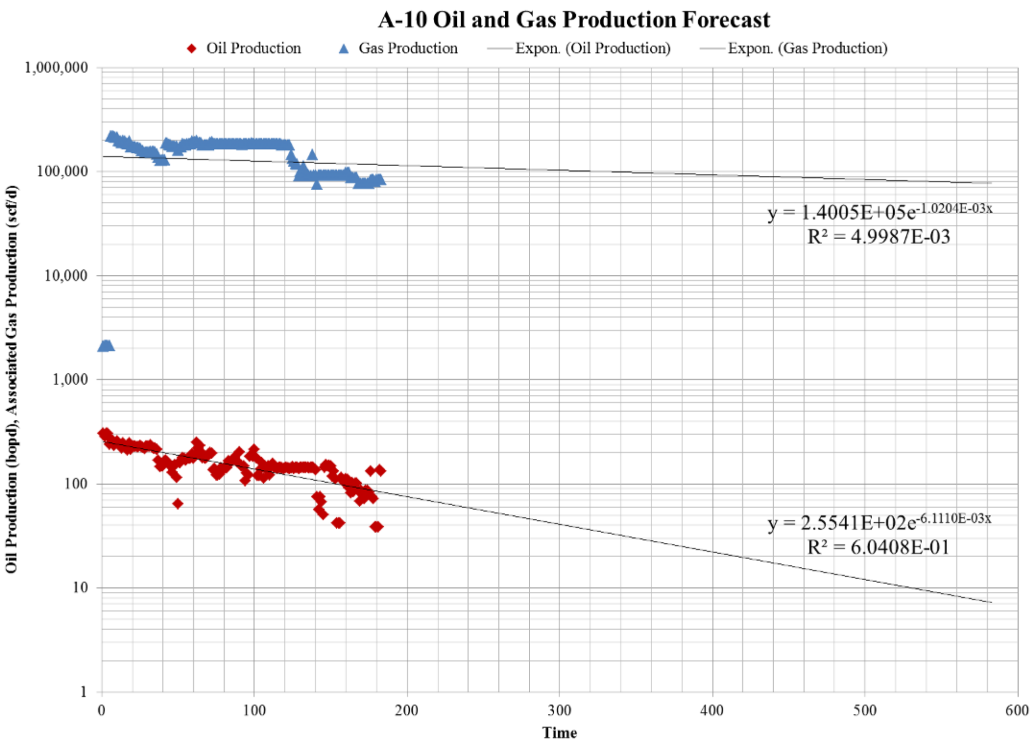

A-03 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
Oil Production (bopd), Associated Gas Production (scf/d)
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600
Time
y = 9.9651E+03e2.2913E-04x
R² = 3.6644E-02
y = 2.7878E+02e-1.0168E-02x
R² = 8.7984E-01

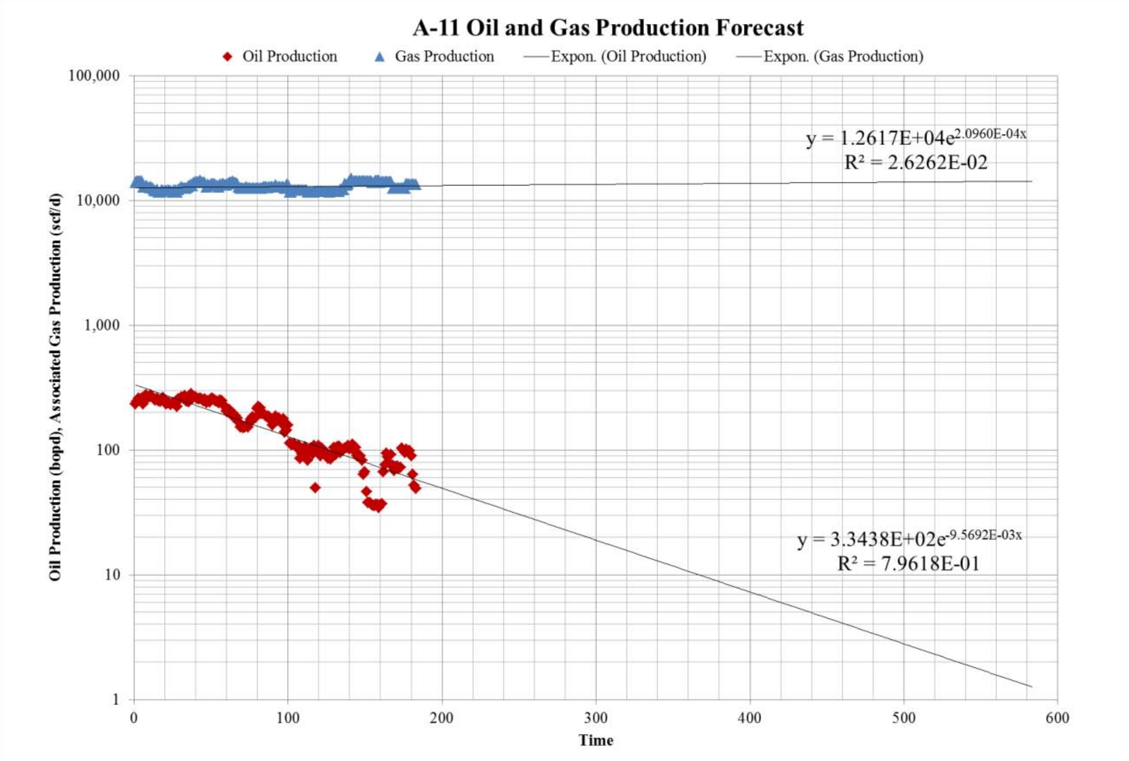

A-04 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
Oil Production (bopd), Associated Gas Production (scf/d)
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600
Time
y = 3.2114E+04e-1.8601E-03x
R² = 3.3189E-01
y = 4.8494E+01e-2.5018E-03x
R² = 7.0506E-01


A-05 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 2.9034E+04e-8.7406E-04x
R² = 1.3804E-01
y = 1.4245E+02e-2.5290E-03x
R² = 8.6060E-02
Oil Production (bopd), Associated Gas Production (scf/d)
Time
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600

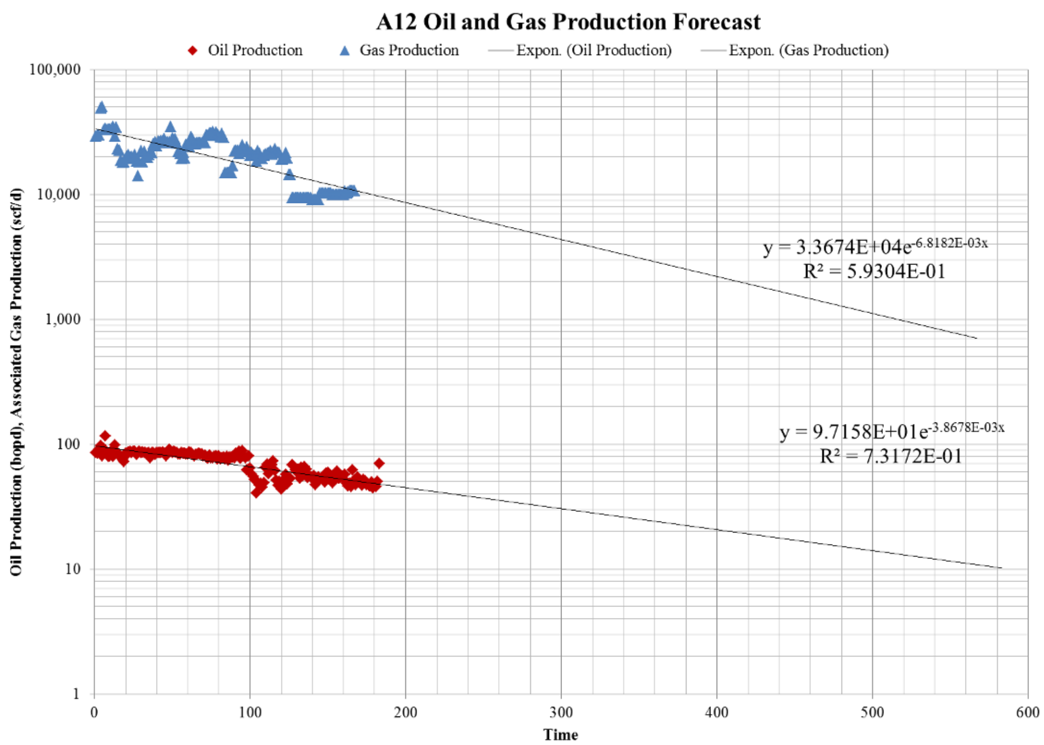

A-08 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 2.8010E+05e-3.6030E-03x
R² = 5.7643E-01
y = 9.6372E+02e-9.3859E-03x
R² = 9.1289E-01
Oil Production (bopd), Associated Gas Production (scf/d)
Time
1,000,000
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600


A-09 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
10,000
1,000
100
10
1
0
100
200
300
400
500
600
Time
Oil Production (bopd), Associated Gas Production (scf/d)
y = 6.4740E+03e-2.1989E-04x
R² = 2.3183E-02
y = 4.7910E+01e-1.1150E-03x
R² = 1.8113E-01

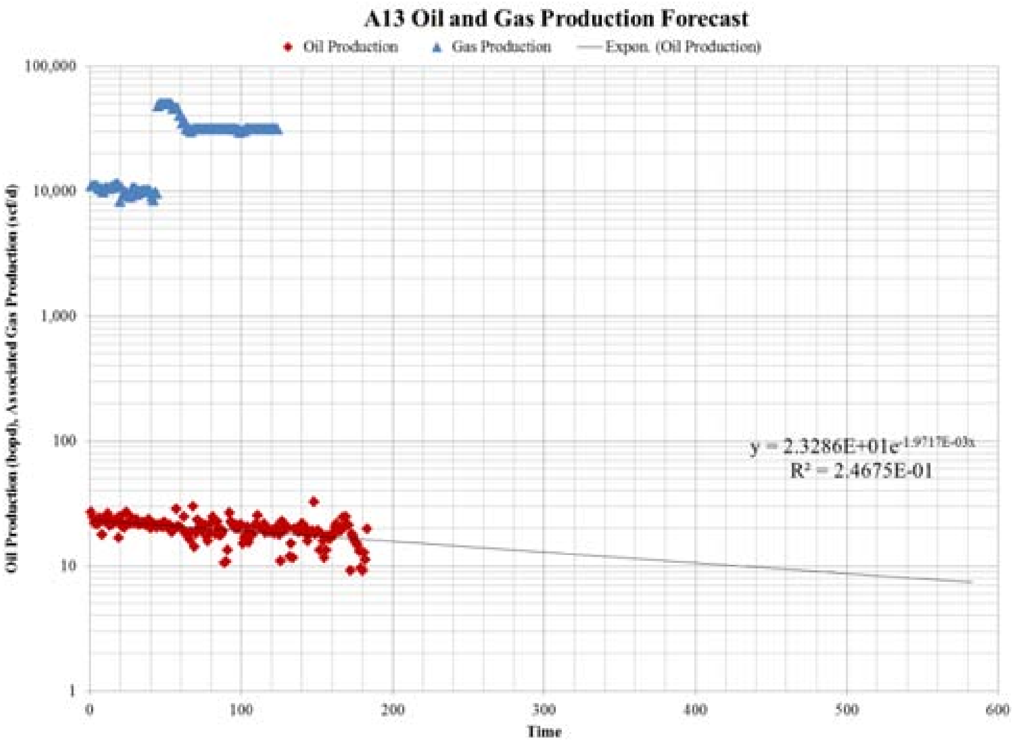

A-10 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
1,000,000
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600
Time
Oil Production (bopd), Associated Gas Production (scf/d)
y = 1.4005E+05e-1.0204E-03x
R² = 4.9987E-03
y = 2.5541E+02e-6.1110E-03x
R² = 6.0408E-01

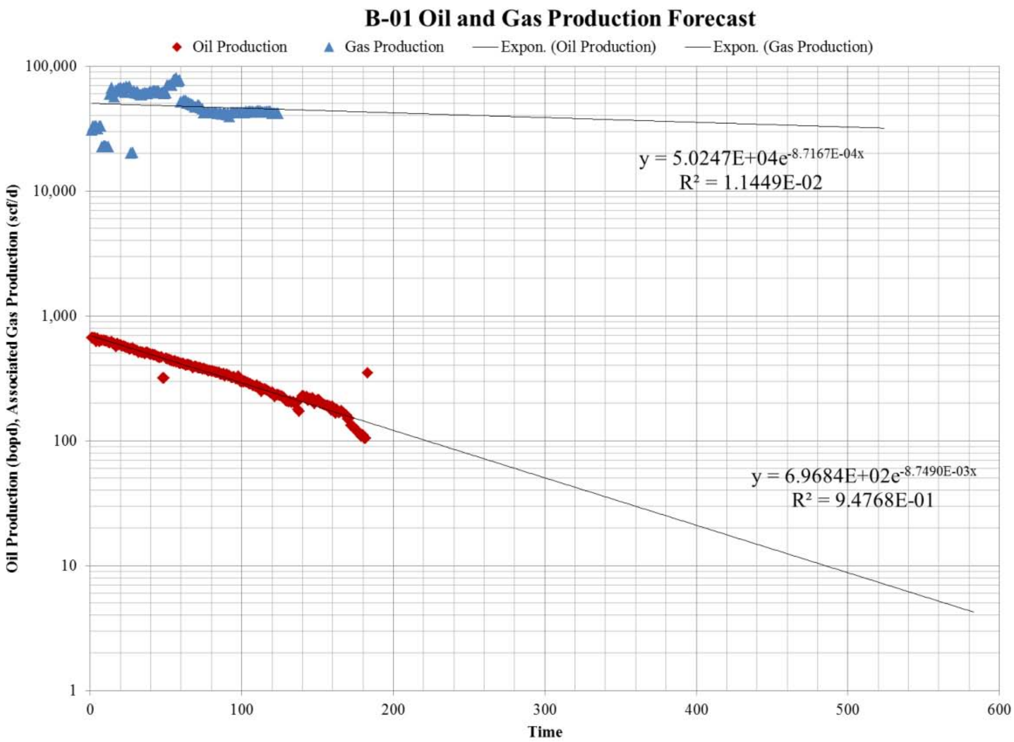


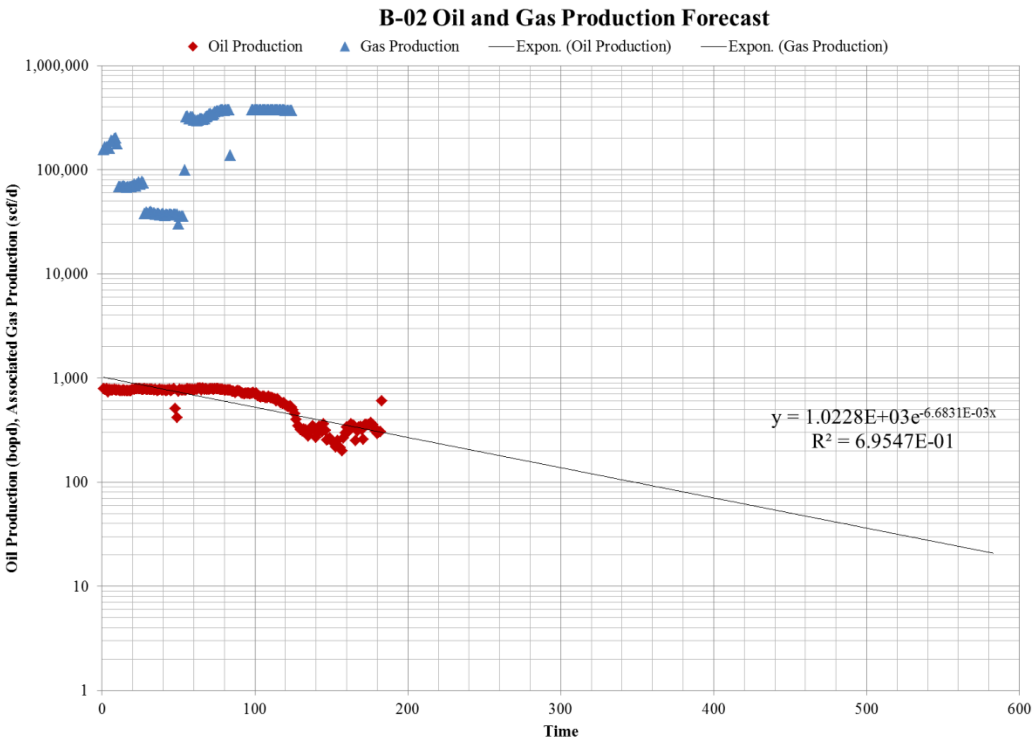
A-11 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 1.2617E+04e^2.0960E-04x
R² = 2.6262E-02
y = 3.3438E+02e^-9.5692E-03x
R² = 7.9618E-01
Oil Production (bopd), Associated Gas Production (scf/d)
Time
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600

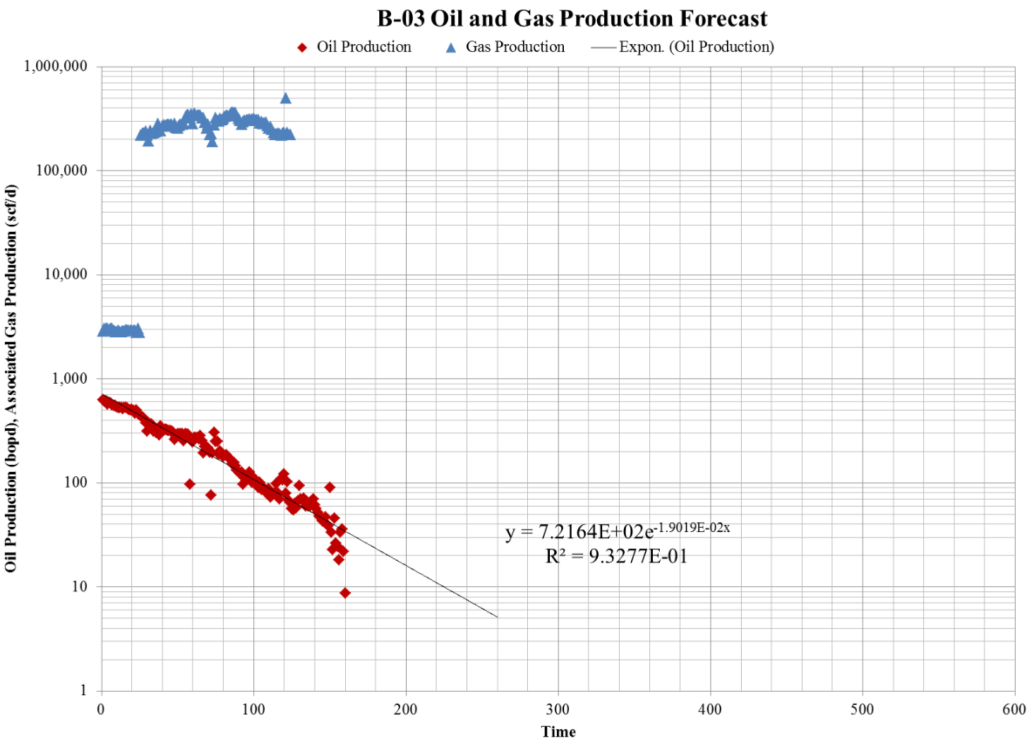


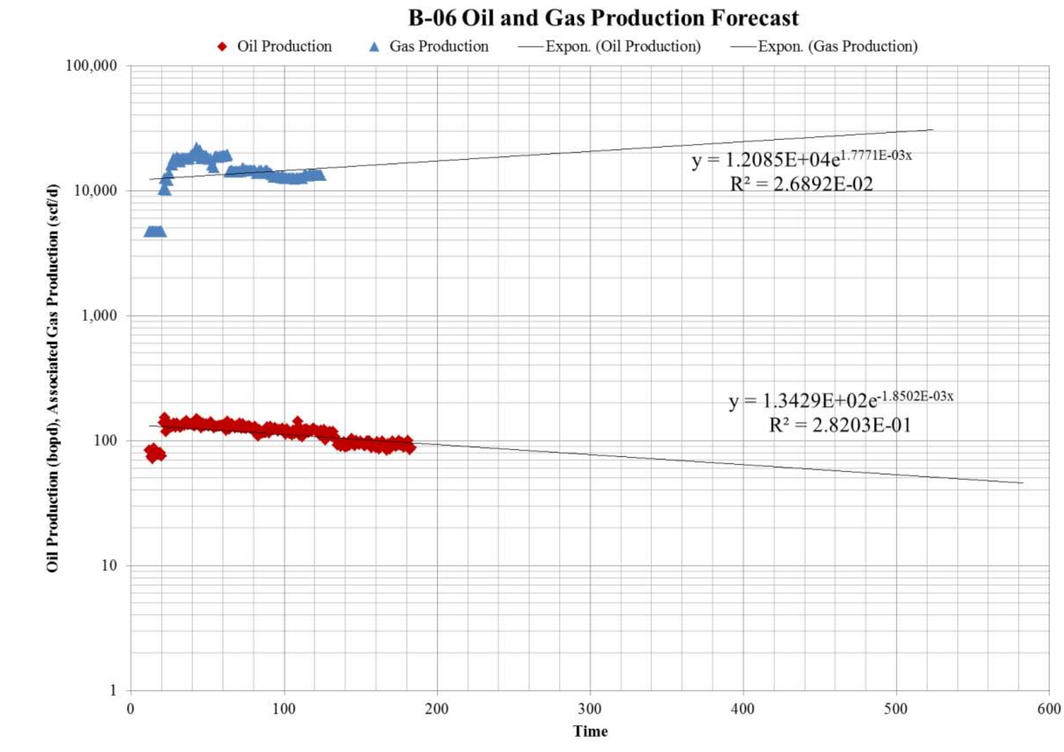
A12 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 3.3674E+04e^-6.8182E-03x
R² = 5.9304E-01
y = 9.7158E+01e^-3.8678E-03x
R² = 7.3172E-01
Oil Production (bopd), Associated Gas Production (scf/d)
Time
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600

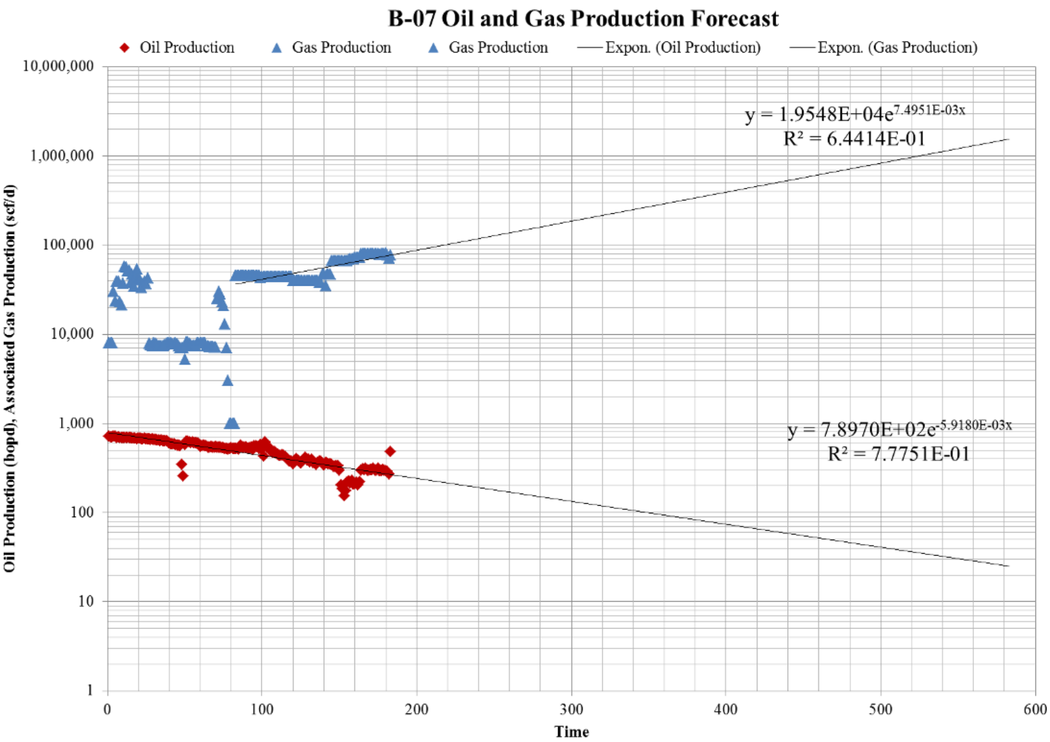

A13 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Oil Production (bopd), Associated Gas Production (scf/d)
Time
y = 2.3286E+01e-1.9717E-03x
R² = 2.4675E-01

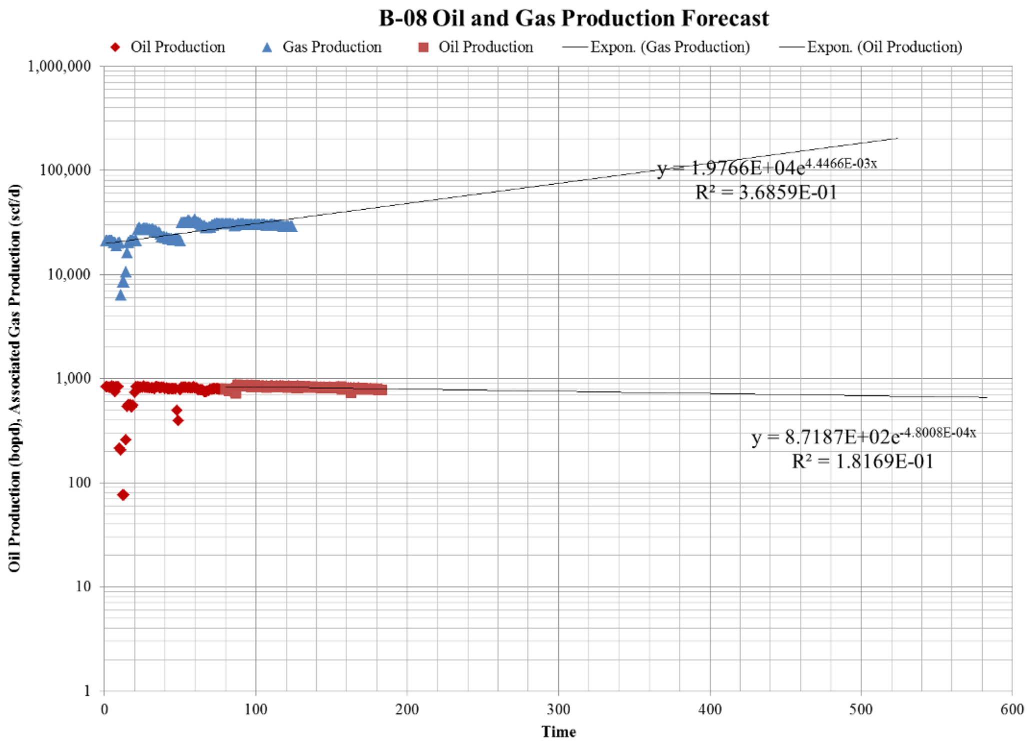

B-01 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
Oil Production (bopd), Associated Gas Production (scf/d)
Time
y = 5.0247E+04e-8.7167E-04x
R² = 1.1449E-02
y = 6.9684E+02e-8.7490E-03x
R² = 9.4768E-01

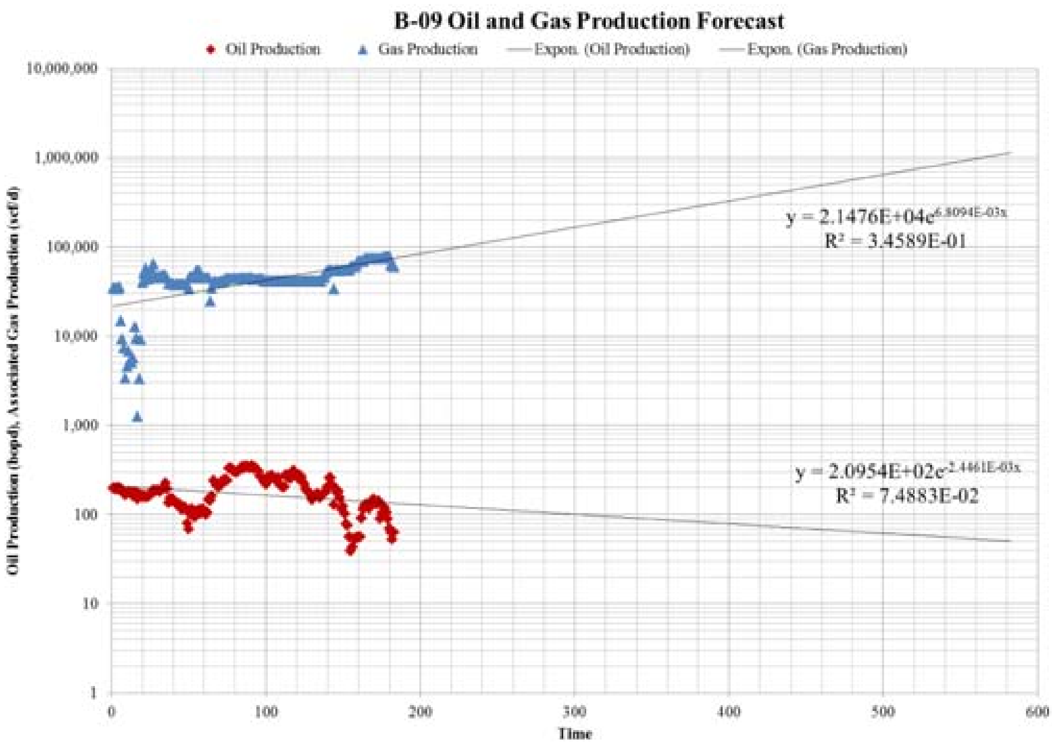

B-02 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
Oil Production (bopd), Associated Gas Production (scf/d)
1,000,000
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600
Time
y = 1.0228E+03e-6.6831E-03x
R² = 6.9547E-01


B-03 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Oil Production (bopd), Associated Gas Production (scf/d)
1,000,000
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600
Time
y = 7.2164E+02e-1.9019E-02x
R² = 9.3277E-01


B-06 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 1.2085E+04e1.7771E-03x
R² = 2.6892E-02
y = 1.3429E+02e-1.8502E-03x
R² = 2.8203E-01
Oil Production (bopd), Associated Gas Production (scf/d)
Time


B-07 Oil and Gas Production Forecast
Oil Production
Gas Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 1.9548E+04e7.4951E-03x
R² = 6.4414E-01
y = 7.8970E+02e-5.9180E-03x
R² = 7.7751E-01
Oil Production (bopd), Associated Gas Production (scf/d)
Time


B-08 Oil and Gas Production Forecast
Oil Production
Gas Production
Oil Production
Expon. (Gas Production)
Expon. (Oil Production)
y = 1.9766E+04e4.4466E-03x
R² = 3.6859E-01
y = 8.7187E+02e-4.8008E-04x
R² = 1.8169E-01
Oil Production (bopd), Associated Gas Production (scf/d)
Time
1,000,000
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600


B-09 Oil and Gas Production Forecast
Oil Production
Gas Production
Expon. (Oil Production)
Expon. (Gas Production)
y = 2.1476E+04e6.8094E-03x
R² = 3.4589E-01
y = 2.0954E+02e-2.4461E-03x
R² = 7.4883E-02
Oil Production (bopd), Associated Gas Production (scf/d)
Time
10,000,000
1,000,000
100,000
10,000
1,000
100
10
1
0
100
200
300
400
500
600

3. Annex I, II, and III countries

Parties to UNFCCC are classified as:

- Annex I countries: industrialized countries and economies in transition
- Annex II countries: developed countries which pay for costs of developing countries
- Non Annex I countries: Developing countries.

List of these countries can be found at Official UNFCCC website (http://unfccc.int/2860.php)

VITAE

Pongsathorn Horpiencharoen was born on October 7, 1985 in Bangkok, Thailand. He received his B.Eng. in Civil Engineering from the faculty of Engineering, Chulalongkorn University in 2008. After graduating, he continued his study in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.